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UTILITIES COMMISSION

AVISTA Corp.

January 30, 2012

Via Overnight Mail
Jean Jewell
Idaho Public Utilities Commission
472 W. Washington Street
Boise, ID 93702

Re: Direct Testimony of Clint Kalich on Behalf of Avista Corporation
IPUC Case No. GNR-E-11-03

Dear Ms. Jewell:

Please find enclosed for filing an original and nine copies of the Direct Testimony of Clint Kalich on behalf of Avista Corporation for filing in the above-referenced proceeding. The first enclosed copy is hereby designated as the reporter's copy. Please let me know if you have any questions regarding this filing.

Sincerely,

Michael G. Andrea
Senior Counsel

Enclosures

cc: Service List

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2012 JAN 31 AM 10: 14
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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE COMMISSION'S REVIEW OF PURPA QF CONTRACT PROVISIONS INCLUDING THE SURROGATE AVOIDED RESOURCES (SAR) AND INTEGRATED RESOURCE PLANNING (IRP) METHODOLOGIES FOR CALCULATING PUBLISHED AVOIDED COST RATES	)	CASE NO. GNR-E-11-03

TESTIMONY OF CLINT KALICH

AVISTA CORPORATION

JANUARY 31, 2012

I. INTRODUCTION AND TESTIMONY OVERVIEW

Q. Please state your name, the name of your employer, and your business address.

A. My name is Clint Kalich. I am employed by Avista Corporation ("Avista") at 1411 East Mission Avenue, Spokane, Washington.

Q. Please state your educational background and professional experience.

A. I graduated from Central Washington University in 1991 with a Bachelor of Science Degree in Business Economics. Shortly after graduation, I accepted an analyst position with Economic and Engineering Services, Inc. (now EES Consulting, Inc.), a northwest management-consulting firm located in Bellevue, Washington. While employed by EES, I worked primarily for municipalities, public utility districts, and cooperatives in the area of electric utility management. My specific areas of focus were economic analyses of new resource development, rate case proceedings involving the Bonneville Power Administration, integrated (least-cost) resource planning, and demand-side management program development.

In late 1995, I left Economic and Engineering Services, Inc. to join Tacoma Power in Tacoma, Washington. I provided key analytical and policy support in the areas of resource development, procurement, and optimization, hydroelectric operations and re-licensing, unbundled power supply rate-making, contract negotiations, and system operations. I helped develop, and ultimately managed, Tacoma Power's industrial market access program serving one-quarter of the company's retail load.

1 In mid-2000 I joined Avista and accepted my current position assisting the
2 Company in resource analysis, dispatch modeling, resource procurement, integrated
3 resource planning, and rate case proceedings. I have participated in proceedings before
4 the Commission since 2000, and cases surrounding PURPA beginning in 2002.

5 **Q. Why are you providing testimony before the Commission today?**

6 A. Avista wants to ensure that its customers receive fair value for the
7 electricity they purchase. This is the basic premise of Public Utility Regulatory Policy
8 Act (PURPA) law: utilities should pay no more than what they otherwise would for
9 Qualifying Facility (QF) deliveries of capacity and energy (i.e., the utilities actual
10 avoided costs). A misalignment between the prices utilities pay for QF power and the
11 utilities' actual avoided costs still exists in some cases in Idaho. Recent QF wind
12 development history illustrates how important it is for rates paid to QFs to reflect the
13 purchasing utilities' actual avoided costs. My testimony provides a framework under
14 which the rates paid for QF power under PURPA cannot greatly exceed the utilities'
15 actual avoided costs and, therefore, the value customers receive for such power.

16 **Q. Please provide an overview of your testimony?**

17 A. My testimony will first provide some background discussions on topics
18 Avista wishes to highlight in this hearing. These include:

19 1) principles of avoided cost,
20 2) key avoided costs concepts – energy and capacity,
21 3) defining utility need,
22 4) valuing power output during periods of utility deficit and surplus, and

5) bifurcation of rates to reflect capacity and energy costs avoided by the purchase of QF power.

After providing some background, my testimony makes the following recommendations:

1) continue limiting published rate eligibility for variable generators to 100 kW,
2) bifurcate all PURPA rate schedules into capacity and energy,
3) provide capacity payments only in those years where the utility is deficient,
4) during periods of utility energy surplus, PURPA rates should be discounted for the transmission costs, including transmission losses, associated with re-selling the surplus power into the market,
5) PURPA contracts should be signed no earlier than five years before commercial operation; fixed prices should be made available no earlier than two years before commercial operation,
6) PURPA contracts should retain meaningful liquidated damage and termination provisions,
7) SAR gas prices should be updated annually for published rates using the Energy Information Administration's Annual Energy Outlook, and
8) the Commission should not determine REC ownership in this docket.

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II. AVOIDED COST BACKGROUND DISCUSSION

Principles of Avoided Costs

Q. Please provide a general discussion of PURPA and avoided costs as it pertains to this proceeding.

A. PURPA was passed in 1978 to help create a market for non-utility electricity supplies.[1] PURPA, and its associated regulations, obligates utilities to buy "energy and capacity which is made available from a qualifying facility" at rates not exceeding the incremental costs to the utility of electric energy and/or capacity which, but for the purchase from the QF, the utility would generate itself or purchase from another source.[2] The rates for such purchases "shall be just and reasonable to the electric consumer. . . ."[3] While the obligation to purchase is mandated by federal law, pricing and many of the terms and conditions of PURPA contracts are left to the state. States have been given wide discretion in setting the rates, terms, and conditions for PURPA contracts, but are required "to put into effect...standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less."[4]

In Idaho, the Idaho Public Utilities Commission (Commission) is responsible for implementing PURPA. The Commission sets rates and methodologies for all QF developers wishing to sell their output in the State of Idaho to one of the utilities regulated by the Commission.

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[1] Today it can be argued that QF developers have adequate access to the marketplace absent the PURPA. For example, utilities generally procure new long-term supplies of electricity through regulated or quasi-regulated competitive acquisition processes that QF developers can bid into. Federal laws and regulations also now obligate utilities to sell or build transmission capacity to/for 3rd parties, enabling QF developers to sell their output to other utility systems or at the major trading hubs.
[2] 18 C.F.R. § 292.101(b)(6) (defining "avoided costs").
[3] 18 C.F.R. § 292.304(a)(1)(i).
[4] 18 C.F.R. § 292.304(c).

1 **Q. Please expand on the definition of avoided cost.**

2 A. Avoided cost is a complex concept, as the 33-year history of PURPA and its
3 implementation in Idaho shows. FERC regulations define avoided costs as meaning "the
4 incremental costs to an electric utility of electric energy or capacity or both which, but for
5 the purchase from the qualifying facility or qualifying facilities, such utility would
6 generate itself or purchase from another source."[5] FERC allows for differentiation of the
7 avoided cost rate based on a number of factors, including consideration of: a) daily and
8 seasonal shaping, b) the ability of the utility to dispatch the resource, c) the demonstrated
9 reliability of the resource, d) the term, termination notice, and sanctions for non-
10 compliance, e) the extent to which outages can be usefully coordinated with utility needs,
11 f) the usefulness of the resource during system emergency, g) the reduction of fossil fuel
12 use, and h) line loss savings or costs attributable to the resource.[6]

13 A simplified interpretation of this provision is that customers should pay no more
14 for a QF purchase than a least-cost alternative to it. And further to this point, customers
15 should pay only an amount equal to the costs that they actually avoid by making the QF
16 purchase; in other words, if no costs are being avoided, the QF developer should not
17 receive compensation for its deliveries under PURPA.

18 **Energy and Capacity Definitions**

19 **Q. How does one define "energy" in the context of PURPA?**

20 A. PURPA does not specifically define energy. According to a March 2011
21 paper by the Pacific Northwest Utilities Conference Committee (PNUCC), energy

[5] 18 C.F.R. § 292.101(b)(6).
[6] 18 C.F.R. § 292.304(e).

1 "measures the quantity of electrical power (i.e., flow) over time."[7] It is measured in watt-
2 hours. In the northwest, energy is generally measured in average megawatts because it
3 measures average consumption over a period of time.

4 **Q. What is the definition of "capacity" in the context of PURPA?**

5 A. In contrast to energy, capacity measures the ability to produce power to
6 meet system load requirements.[8] It is a generic term often requiring the use of a
7 descriptor, such as "nameplate" capacity or "net winter" capacity. In the context of
8 PURPA, many of the avoided cost considerations listed earlier in my testimony require
9 differing types of capacity.

10 An important concept for PURPA in Idaho is the on-peak capacity contribution of
11 a resource. In other words, the resource's ability to reliably generate during times of the
12 utility system's peak. Absent the ability to reliably generate during peak-period hours,
13 there are no avoided capacity costs because, notwithstanding the existence or non-
14 existence of the QF, the utility will need to build or otherwise acquire a resource to
15 generate during times of the utility system's peak. FERC has acknowledged this point in
16 its rules.[9] Therefore, a QF that cannot be relied on to generate during times of system
17 peak does not avoid any utility capacity costs. It follows that a QF that cannot be relied
18 on to provide on-peak generation should not receive any payment for the capacity portion
19 of the PURPA avoided cost rate.

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[7] http://pnucc.org/documents/CapabilitiesofResourcesReportandMemoweb.pdf.
[8] The "ability" to produce power, in the case of wind and other variable and fuel-limited renewables, also means that the resource has fuel adequate to generate power during the peak system load requirement.
[9] 18 C.F.R. § 292.304(e)(2) states that the rate shall be based on: "the availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods."

Q. How should the on-peak contribution of a QF resource, and the level of its capacity payment, be determined?

A. The contribution should be determined in a manner similar to how the utility identifies the on-peak capacity contribution of its other resources. A first step is to determine the expected, or average, on-peak contribution. For example, the QF developer must supply a "12x24" matrix of its expected future deliveries as part of the contracting process. This means the QF developer provides one estimated 24-hour shape of power output for each calendar month. From this shape much can be learned. For example, an irrigation canal hydroelectricity facility's 12x24 matrix will show clearly that no generation is delivered to the utility during the winter months. So, in Avista's case where on-peak capacity benefits are defined by winter output, an irrigation canal hydroelectricity facility is not able to generate during Avista's winter peak and, therefore, the capacity contribution is zero.

The analysis is more complicated if the utility system peaks during the summer when the canal project is expected to generate at some level during peak load periods. Capacity planning based on statistical averages, like the 12x24 matrix, has the potential to compromise reliability because during approximately half of future contract years the resource will not perform at the average level of capacity. A statistical approach to quantifying a QF resource's capacity, similar to how the utility does its other capacity planning, should be applied. Absent a long period of historical record to evaluate the contribution, the QF resource should receive a capacity contribution based on levels for similar resources identified by the utility in its Integrated Resource Plan (IRP).

Q. Does this approach work for resources other than irrigation canal hydro used in your example above?

A. Yes. For Avista's IRP the on-peak capacity contribution of each major resource type is input into its Preferred Resource Selection Model (PRiSM). I recommend that values from the IRP be used to set the on-peak capacity values in PURPA contracts except possibly for wind where a small contribution might be used. Based on Avista's IRP, the following on-peak contributions would be applied to QF developer projects.[10] Contributions are reduced for operating reserves the utility is obligated to provide as part of its membership in the Northwest Power Pool.

Table 1 – Avista On-Peak Capacity Contributions from 2011 IRP

Resource	Contribution	Resource	Contribution
Canal Hydro	0%	Solar	5%
Wind	0%	Biomass	93%

Q. You mention that you might support a small on-peak contribution for wind. What level will you support?

A. Without a geographically diversified portfolio of wind it is difficult to assign any on-peak contribution value for wind. It is Avista's concern for maintaining system reliability that it assigns no capacity value to wind in its IRP. This said, the Northwest Power and Conservation Council (NPCC) uses a regional on-peak capacity benefit of five percent. To be consistent with the NPCC, I will support a five percent on-peak capacity contribution for wind for PURPA projects. However, Avista will continue assigning wind a zero on-peak capacity value in its planning assessments, including the

[10] Values represent winter on-peak contribution. For example, canal hydro operates during the spring and summer months, with no output during the winter. Avista's wind rating is low due to the lack of wind diversity in its portfolio.

IRP, until such time as an adequately diverse portfolio of wind exists in its service territory.

Definition of Utility Need

Q. Should utility need be a factor in the price paid for QF power?

A. Yes. There is a vast difference in the costs avoided by the QF resource depending on whether the utility is filling a resource deficit with QF power, or the utility already has resources adequate to meet its load obligations. When deficit, avoided costs are those that would be paid for a least-cost alternative resource or resources providing equivalent value. When the utility is in a surplus position, it will not avoid any costs as a result of the QF purchase; at most, the actual value of the QF purchase to the utility is only the avoided fuel costs at existing facilities. A more generous interpretation of the PURPA obligation is to compensate a QF developer during times of system surplus at the market price received for the sale of the energy net of delivery costs to a market trading hub.[11]

Q. In Order 29124 the Commission eliminated from consideration utility need in the calculation of published avoided cost rates, relying substantially on the concerns expressed by Staff. What has changed to support your position that the Commission should reverse course?

A. In Order 29124, the Commission expressed nine reasons in support of removing the first deficit year. The concerns in 2002 should not exist today.

[11] For example, the short-term PURPA rate is 85% of the market index price, with the reduction intended to compensate the utility for delivery of the surplus to the market.

1 **Q. What was the first reason, and what has changed to again support**
2 **considering first year deficits?**
3 A. The first concern was the lack of regular filings before the Commission
4 that outline utility deficit years. Since 2002 much has changed. Utilities now file
5 biennial IRPs outlining future deficit year explicitly. Each IRP is developed with
6 participation from Commission staffs and other interested stakeholders.
7 To determine Avista's future needs, one needs to look no further than the third
8 paragraph of our August 2011 IRP filing. The document states our needs very clearly:
9 "absent new resource additions or new conservation measures, annual energy deficits
10 begin in 2020…the Company will be short 98 MW of summer capacity in 2019…winter
11 capacity deficits begin at 42 MW in 2020." Language similar to this has been included in
12 all recent Avista IRPs as far back as 2003. The fact that utilities are clearly defining their
13 resource needs in regularly-filed IRP's should eliminate this concern.
14 **Q. What was the second reason, and has it been resolved?**
15 A. The Commission was concerned with the lack of clarity of what exactly
16 the deficit year represented, and whether the determination should be based on an energy
17 or capacity need. As expressed in my previous answer, Avista now tracks both energy
18 and capacity deficiency positions. My proposal, to be fleshed out later in testimony, is to
19 pay for each of these components separately based on separate utility needs for each.
20 With this resolved, the 2002 concern should be fully resolved.
21 ///
22 ///

Q. What was the third reason, and why should it no longer concern the Commission?

A. The third concern was that key planning assumptions greatly affect the result, and that assumptions can vary by utility. While it still is true that planning assumptions differ between the utilities and affect the ultimate deficit year or years, utility IRP processes are subject to significant oversight, both by Idaho Commission Staff and other utility commission staff, and interested parties—including utility customers and potential QF developers. Each utility certainly is different and, therefore, each utility needs to have different assumptions. As such, the balancing of loads and resources that each utility undertakes is for reasons much greater than PURPA, including system reliability, least cost, and meeting environmental and oither social policies.

The bottom line is that, with regularly-updated IRPs benefitting from public and Commission oversight, there is a consistent basis for determining load and resource balance such as developed in the utility's IRP.

Q. The fourth concern was that utilities prepare their own load forecasts with little oversight, and that they can be manipulated. Has this changed?

A. I am not aware of any load forecast concerns over the five past IRPs (2003-present) planning cycles that I have led. But, as explained in my answer to the third concern, regular IRP timelines should eliminate this concern too. The utility load forecast is presented to Staff and other participants in the Company's public IRP process; questions about the forecast can be aired and addressed in that public process.

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1 **Q. What was the fifth concern, and why should it no longer be of concern?**

2 A. The Commission was concerned there was not adequate consistency
3 regarding how long-term market purchases were considered in utility planning. This
4 concern has been addressed. I believe there is general consensus now that any contract,
5 including one for PURPA power, that obligates a seller to sell and a utility to buy power
6 should be included in the load and resources tabulation.

7 **Q. Staff also reasoned in 2002 that the difference between PURPA rates**
8 **during surplus and deficit periods were not great and that the importance of the**
9 **deficit year had diminished. Does this reasoning hold today?**

10 A. No. With a more accurate payment for QF power through the bifurcation of
11 energy and capacity payments as proposed in this testimony, there is a significant
12 difference between payments in deficit and surplus periods. As I explained above, the
13 needs of the utility are essential to successfully honor avoided cost principles, especially
14 in light of the significant additions of variable generation resources to utility systems
15 since 2002. And, as I will show later in my testimony, it is imperative that the
16 Commission recognize the deficit years for energy and capacity to ensure appropriate
17 avoided cost payments are made.

18 **Q. What was the seventh concern? Is it still valid?**

19 A. The seventh concern was that utilities tend to be surplus in the near term,
20 and that avoided cost rates should not provide incentives for a utility to increase its length
21 to avoid having to purchase PURPA power. It is often true that utilities are surplus in
22 early years; being so is an essential part of providing reliabile utility service. It also is
23 true that QF developers would be affected by these surpluses were they to receive lower

early-year payments during surplus years. But this effect is a reflection of true avoided costs. It is not reasonable to hold a utility system short both of capacity and reliability simply to promote QF development. So in the early years of a long-term contract, QF developers might receive a lower payment reflective only of the energy value of their projects. But out beyond this time the payment will increase with the utility's need for the QF resource. QF developers also have the opportunity to contract with the utility and postpone their development and deliveries until such time as a deficiency occurs.

Q. Does reasoning in 2002, that PURPA project development does not have a large impact on utilities' load and resource balance, hold today?

A. No. As recent history shows, PURPA development can start and stop very quickly. The result can be many contracts and hundreds of megawatts of new, and often unneeded, supplies. These figures are not small, especially for a utility like Avista that is growing at fewer than 30 MW per year.

Q. Do you have any comments with regard to the last reason that supported the 2002 decision to eliminate the consideration of the utility deficit year?

A. Yes. Staff's position in 2002 was that volatile energy prices of that period, and the SAR's linkage to them during periods of utility surplus, posed difficulty when estimating PURPA payments during surplus years. Today we have better options to avoid this volatility and provide the QF developer with a more stable price in surplus years. As explained later in my testimony, I believe that it is possible to provide a fixed payment during surplus years that does not fluctuate over the contract term, and is tied to the actual expected operating costs of the SAR.

1 **Q. In re-establishing the deficit year, how should utility needs be**
2 **defined?**
3 A. Utility needs should be defined using a publicly-available information
4 source—the biennial utility IRP. The IRP defines the future needs for both energy and
5 capacity on the utility's system, and, as noted before, is developed with participation
6 from Commission staffs and other stakeholders. Each plan defines the timeframe of
7 future deficits.
8 **Q. Should load changes since the IRP be considered in the tabulation of**
9 **utility need?**
10 A. Yes. Limited updates should be considered, including changes resulting
11 from a new load forecast, and new contract obligations (e.g., new PURPA contracts) and
12 deliveries incurred since the publication of the IRP. If there is a concern over, for
13 example, the load forecast, the Commission could be consulted to assist the parties in
14 resolving their differences. Alternatively, and at their option, utilities could file annual
15 IRP resource balance updates with the Commission.
16 **Q. What happens if a utility is deficit in one of the two PURPA**
17 **components (energy or capacity), and not in the other?**
18 A. As I explain in more detail in other portions of my testimony, QF
19 developers should only receive payments for capacity when the utility has a capacity
20 need. Compensation for energy should be based on a separate tabulation of energy needs.
21 If the utility is in a deficit energy position, the payment should be determined
22 independently of the capacity need and based on the value of that energy to the utility. If

1 the utility is surplus energy, the energy payment should be reduced by the costs of
2 delivering the surplus power to the market (i.e., transmission and associated losses).

3 **PURPA Rates During Periods of Utility Deficit and Surplus**

4 **Q. How does the concept of utility need apply to PURPA?**

5 A. The principle concept to utilities buying QF power is paying no more than
6 avoided cost. In other words, what least-cost resource and/or acquisition would be
7 avoided with the delivery of QF power under PURPA? Where no costs are avoided by
8 the utility with the addition of a QF, the QF does not reduce the utility's system costs. In
9 the most basic interpretation, the utility would pay nothing for QF power where no costs
10 were avoided; however, another policy position could be that where a market exists for
11 selling surplus energy from the QF, the QF is paid the market value for its energy.[12] No
12 similar active market exists for capacity and no significant value can be obtained through
13 remarketing capacity surpluses created by QF purchases. Because of this, QF developers
14 should receive payments for capacity only when the utility is deficit.

15 **Bifurcation of the PURPA Rate**

16 **Q. Do rates presently paid to QF developers accurately reflect actual**
17 **avoided costs?**

18 A. It depends. Avoided cost rates calculated using the IRP methodology for
19 QFs above the eligibility cap for published avoided cost rates (i.e., 100 kW for wind and
20 solar QFs, and 10 aMW for all other QFs) reflect actual avoided costs because the

[12] While historically utilities doing business in Idaho have paid for QF power even when they are in a surplus position because there has been a market for such energy, there may be structural changes in the region, such as higher levels of wind, increased transmission constraints, and increased prevalence of negative prices, that may at some point require a re-evaluation of that position.

1 specific values of the resource are considered uniquely. However, the prices paid to
2 QF's under published avoided cost rates can exceed actual avoided costs.

3 **Q. Please explain why prices paid to QFs under published avoided cost**
4 **rates can exceed actual avoided costs.**

5 A. The Commission sets rates that utilities must pay all QF developers below
6 an eligibility cap based on a Surrogate Avoided Resource (SAR). The SAR used to set
7 the published avoided cost rates is a gas-fired combined-cycle combustion turbine
8 (CCCT). Today all QF resources below the cap are compensated at a single rate
9 assuming equivalency to the SAR–i.e., the delivery of both energy and capacity–even if
10 the QF resource is variable and/or provides little or no capacity.[13] As a result, the
11 published rates for variable resources can significantly exceed actual avoided costs. This
12 result is not equitable to customers in the case of variable energy QFs like wind, as
13 payments are inclusive of energy <u>and</u> capacity, yet the costs of new capacity investment
14 are not being avoided.

15 **Q. What are the consequences of a published avoided cost rate exceeding**
16 **actual avoided cost?**

17 A. The recent experience of some utilities in Idaho shows a "boom" in QF
18 wind development can be a significant consequence that likely would not have been
19 possible absent the structure of published avoided cost rates in Idaho that provided a
20 published avoided cost rate that exceeded the actual avoided costs of wind QFs. That is,

[13] Some differentiation exists based on time of day, seasonality, and integration charges. Wind resources are subject to a wind integration charge that reduces the QF payment by approximately 10%; however, this reduction is for the *consumption* of capacity due to wind integration, not a discount for the fact that the resource does not provide on-peak capacity. Wind "consumes" capacity because existing non-wind capacity resources must be dedicated to following and integrating the variable wind generation.

inflated PURPA prices incented QF developers to construct more wind QFs and sell the output in Idaho. The result is that utility customers bear inflated costs.

III. THE COMMISSION SHOULD LIMIT VARIABLE GENERATOR PUBLISHED RATE ELIGIBILITY TO 100 KW

Q. Should the Commission continue to limit variable generation resource (i.e., wind and solar) access to published rates to 100 kW?

A. Yes. The ability of variable generation resources to break into smaller projects solely for the purpose of qualifying for published rates is well documented and should not be allowed. The best means to prevent this is to keep the 100 kW cap for variable generation resources. Further, the Commission's 100 kW limit for variable generator published rate eligibility is a reasonable limitation and is consistent with federal law. I support the continuation of this limit indefinitely. Large variable QF resource additions should be considered on a case-by-case basis to ensure that the prices paid for the QF output reflect the actual avoided cost associated with the particular QF resource.

IV. CUSTOMERS ARE BEST PROTECTED THROUGH BIFURCATION OF PURPA RATES INTO SEPARATE ENERGY AND CAPACITY COMPONENTS

Q. Should the Commission continue to offer a single combined rate for capacity and energy?

A. No. The avoided costs of various QF technologies can be vastly different. Some technologies, such as landfill gas, act very much like the SAR, providing both significant contributions in meeting on-peak demand (i.e., capacity), as well as energy. Other resources, such as wind, provide little or no capacity and, therefore, the purchase of the output from such resources under a PURPA contract will not avoid significant capacity investments in alternative resources. Payments to such resources providing little

1 or no capacity should be lower than a SAR-equivalent resource. But resources providing
2 on-peak capacity similar to the SAR, but generating less energy on an annual basis than
3 the SAR, such as drop canal hydro projects located in a summer-peaking system, have the
4 potential for much higher per-MWh rates under bifurcation.

5 **Q. Please explain why QF developers should be paid separately for**
6 **capacity and energy.**

7 A. Under FERC regulations, a utility obligation exists to purchase energy and
8 capacity from a QF at a price reflective of the value of a QF resource.[14] Further, FERC
9 allows that rates "may differentiate among qualifying facilities using various technologies
10 on the basis of the[ir] supply characteristics.[15] One of the largest differences among QF
11 facilities is their ability to provide varying levels of energy and capacity.

12 **Q. How do you propose that the Commission ensure that actual avoided**
13 **costs are not exceeded?**

14 A. The Commission's adoption of a lower eligibility cap (100 kW) for wind
15 and solar resources is a significant first step in mitigating the problems associated with
16 paying published avoided cost rates to variable resources because: (i) it is now more
17 difficult for wind and solar QF developers to disaggregate large projects to take
18 advantage of published avoided cost rates, and (ii) the avoided cost rate for most wind
19 and solar projects will be calculated using the IRP methodology, which more accurately
20 reflects the actual avoided costs.[16] The Commission should retain this limitation. The
21 Commission also should bifurcate avoided cost rates into the separate components of

[14] 18 CFR § 292.303
[15] 18 CFR § 292.304(a)(3)
[16] The IRP Methodology allows the use of updated pricing assumptions (e.g., current natural gas prices, utility need for the resource).

energy and capacity. In this way, those resources not reducing utility system requirements (i.e., capacity) or bringing value similar to a utility option are not compensated beyond their actual value.

Q. Do you have a recommended method to separate the values of capacity and energy for published rates?

A. Yes. And the basic principles apply to both the SAR and IRP Methodologies. The Commission is charged with establishing appropriate avoided cost rates for QF facilities as it relates to capacity and energy. While there might be other methods available to the Commission, for published rates the simplest would be to change slightly the structure of payments.

The following table provides an overview of my recommended method for establishing published avoided cost rates.

Table 2 – Recommended Published Rate Bifurcation Method

Rate	Method Summary	Units
Capacity	CCCT SAR for "Fueled" projects	$/MWh
Energy	CCCT SAR for "Non-Fueled" projects less CCCT SAR for "Fueled" projects	$/MWh

Q. Please explain your reasoning for creating a new published capacity rate.

A. Each published rate-eligible QF developer enabling the utility to avoid capacity investments, irrespective of its fuel source, receives a payment based on the "Fueled" rate and its on-peak capacity contribution. The present Fueled rate approximates the fixed costs of owning and operating the SAR, and approximates the

1 cost of capacity.[17] No new base calculations are required to determine the capacity
2 payment because the Commission already calculates a Fueled rate.

3 **Q. How would your proposed method account for two resources with**
4 **similar on-peak capacity contributions, but different generation characteristics?**

5 A. It is not fair to pay one resource with a low capacity factor and an
6 equivalently high on-peak contribution the same per-MWh payment as second base load
7 plant operating with a relatively high capacity factor all year round. Using the method,
8 the low capacity factor resource would receive much lower total compensation even
9 though the resource provided the same on-peak capacity benefit to the utility. To ensure
10 a similar payment is made for a similar on-peak capacity contribution, the first step is to
11 covert the SAR per-MWh payment level to a total annual capacity payment. This is
12 accomplished by multiplying the per-MWh rate of the Fueled schedule by the assumed
13 net capacity factor of the SAR resource. This value is then divided by the expected
14 annual capacity factor of the specific QF resource to arrive at a per-MWh rate. The
15 following table illustrates this concept where you have differing resources providing
16 different on-peak capacity contributions. Consistent with my proposal, I used the
17 levelized fueled rate as a proxy for capacity value.

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[17] It does not include fuel and variable operating costs, those generally associated with energy production.

Table 3 – Comparison of QF Project Capacity Payments

Line	Item	SAR	Geo	Hydro	Solar	Wind	Note
1	Resource Size (MW)	1	1	1	1	1	assumption
2	Capacity Contribution (%)	100	100	100	35	5	assumption
3	SAR 20-Year Lev. Fueled Rate (2013 First Year Delivery, $/MWh)	25.51					from present Avista PURPA rate schedule
4	Net Capacity Factor	92.0%	85.0%	34.0%	22.6%	33.0%	assumption
5	Annual Generation (MWh)	8,059	7,446	2,978	1,980	2,891	line 1 * line 4 * 8,760 hours
6	Annual Capacity Payment ($000s)	206	206	206	72	10	SAR line 6 * line 2 / SAR line 2
7	Capacity Payment ($/MWh)	25.51	27.61	69.03	36.35	3.56	line 6 / line 5

The table shows that payments can greatly exceed or fall below the SAR rate based on the capacity contribution and expected, or average, output of the resource. The hydro example shows how this low capacity factor resource receives a per-MWh capacity payment much higher than the SAR resource. The table also shows how a solar resource, even though it has a much lower on-peak capacity contribution can still receive a per-MWh payment exceeding the SAR resource with a 100% on-peak contribution.[18] The table shows that the payment for wind is much lower than the SAR, primarily because of its low on-peak contribution.

Q. What do you mean by "on-peak contribution"?

A. For customers to derive a capacity benefit (i.e., for the utility to avoid capacity investment costs) from the PURPA project, the QF must be capable of reliably generating during peak load hours of the year. If the QF cannot be relied on to generate during the utility's peak load hours of the year, the utility will have to build or otherwise procure a resource that the utility can rely on to generate during those peak load hours and, therefore, the QF does not avoid any capacity investment costs. This means the QF must be capable of reliably providing output during peak hours in the winter months for

[18] The price assumes the solar resource is located in a summer-peaking utility location. Where located in a winter-peaking utility's territory, like Avista, the payment likely will be much smaller.

1 Avista, and likely during the summer months for both Idaho Power and PacifiCorp.[19]
2 Eligibility for capacity payments must be tied to the expected on-peak contribution of the
3 QF resource.

4 **Q. Do you have any other recommendations with regard to published**
5 **rate capacity payments?**

6 A. Yes. With my proposal I recommend changing the rate for capacity in the
7 published tables to a per-MW price instead of a per-MWh price, and then footnote that
8 the payment made to the QF developer will be dependent on the capacity factor and on-
9 peak capacity contribution of the resource. It might also be useful to provide one or more
10 example calculations to show how the capacity payment is "translated" to a per-MWh
11 charge. To make things less confusing, the "Fueled" rate schedule should be re-named as
12 the "Capacity" rate schedule.

13 **Q. Table 3 explains that the per-MWh capacity payment rises as the**
14 **capacity factor of the resource falls. What is to prevent a QF developer from under-**
15 **estimating the QF's capacity factor to obtain higher total compensation for its**
16 **capacity contribution?**

17 A. After the annual SAR-based capacity payment is calculated, it should
18 serve as a cap on total payments in any given year to remove any incentive for a QF to
19 under estimate output.[20] If the QF developer is shown over time, say over two or five
20 years, to have substantially under-estimated the QF's capacity factor, I believe that the
21 capacity rate should be adjusted downward accordingly.

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[19] Idaho Power and PacifiCorp are "summer-peaking" utilities, as documented in their biennial integrated resource plans.
[20] Adjusted based on the specific capacity factor of the QF resource.

1 **Q. Please explain your reasoning for a new published energy rate.**

2 A. Under my proposal, QF projects eligible for the Fueled rate would receive
3 payments for their energy as they do today–based on a gas index. But "Non-Fueled"
4 projects like wind and biomass would receive payments based on the variable operating,
5 variable maintenance and fuel costs associated with the SAR. This value is arrived at by
6 reducing the Non-Fueled SAR rates by the Fueled (Capacity) rates.

7 **Q. Do you have any other recommendations with regard to published**
8 **rate energy payments?**

9 A. Yes. To again make things less confusing, I would name this modified
10 "Non-Fueled" rate schedule (i.e., the Non-Fueled rate schedule less the Fueled rate
11 schedule) as the "Energy" rate schedule.

12 **Q. How would the changes you propose affect the major QF**
13 **technologies?**

14 A. The major change is that QF resources eligible for published avoided cost
15 rates, to the extent they provide significantly less capacity than the SAR, receive a lower
16 rate more commensurate with the costs they enable the utility to avoid. For example, if a
17 wind resource provides a five percent peak capacity value to the utility, it would witness
18 a reduction in the capacity component of the avoided cost rate that would be reflected in
19 its PURPA compensation. Biomass resources likely would be affected only modestly, if
20 at all, because they tend to provide system capacity all year round. Solar would fall
21 somewhere in the middle based on its expected contribution to utility system peak.
22 Hydro resources would benefit greatly relative to the existing structure. See the
23 following table, a continuation of Table 3.

Table 4 – Comparison of QF Project Total Payments

Line	Item	SAR	Geo	Hydro	Solar	Wind	Note
1	Resource Size (MW)	1	1	1	1	1	assumption
2	Capacity Contribution (%)	100	100	100	35	5	assumption
3	SAR 20-Year Lev. Fueled Rate (2013 First Year Delivery, $/MWh)	25.51					from present Avista PURPA rate schedule
4	Net Capacity Factor	92.0%	85.0%	34.0%	22.6%	33.0%	assumption
5	Annual Generation (MWh)	8,059	7,446	2,978	1,980	2,891	line 1 * line 4 * 8,760 hours
6	Annual Capacity Payment ($000s)	206	206	206	72	10	SAR line 6 * line 2 / SAR line 2
7	Capacity Payment ($/MWh)	25.51	27.61	69.03	36.35	3.56	line 6 / line 5
8	Energy Payment ($/MWh)	45.45					SAR line 10 – SAR line 7
9	Integration ($/MWh)	0	0	0	(6.50)	(6.50)	
10	Total (combined) PURPA Rate ($/MWh)	70.96	73.06	114.48	75.30	42.51	SAR from schedules other resources, lines 7 + 8 + 9

As shown, PURPA rates (line 10) can vary significantly depending on the resource type under this proposal. It is also important to point out that these prices assume the utility has both capacity and energy needs throughout the delivery period.[21] The annual capacity payment (line 6) for geothermal is the same as the SAR because the expected output is the same, even though the per-MWh rate differs due to a difference in expected annual MWh output. Solar obtains a capacity payment premium relative to the SAR because its capacity contribution relative to its capacity factor is higher than the SAR ratio.[22] Wind receives a much lower overall payment because only a small on-peak capacity contribution is attributed to the resource. The largest winner using this method is the canal drop hydro facility because it, in this example, provides capacity and operates at a low capacity factor relative to the SAR. So to compensate it for avoided capacity

[21] Drop canal hydro facilities would not receive a capacity payment in winter-peaking systems, since the resource does not generate during the winter. The on-peak capacity payment likely would differ for solar in a winter-peaking system because the resource generates significantly less during winter on-peak hours relative to on-peak summer hours. There also would be discounts in periods where the purchasing utility is surplus energy to account for costs necessary to deliver the surplus energy to a market trading hub.

[22] Again, this assumes that the solar resource is located in a summer-peaking utility territory where on-peak contributions are higher than in a winter-peaking system.

costs, its rate per MWh must rise. Please note that I have simplified the energy payment line (line 8) for hydro, solar and wind in this example. These resources will receive a modified payment depending on their specific energy shape over the year. For example, a solar plant likely would obtain a slightly larger energy payment because its generation is correlated with peak load periods. Wind might get a slightly lower energy payment given that wind tends to have a slight bias toward off-peak hours.

Q. How will the bifurcation affect resources obtaining their pricing through the IRP Method?

A. The IRP Method will conceptually follow the structure described above. The utility purchasing from a QF will pay the QF for energy based on the energy costs avoided by the utility. The utility also will pay only for capacity based on the capacity costs that are avoided due to the QF.

V. QF DEVELOPERS SHOULD RECEIVE PAYMENTS FOR CAPACITY ONLY WHEN THE UTILTY IS DEFICIT

Q. What should QF developers be paid when the utility is deficit?

A. When the utility is deficient, the QF developer should be compensated based on the costs the utility and its customers avoid by not having to invest in alternative power sources. This value is best identified by a recent competitive acquisition process or the utility's latest IRP, both adjusted for any significant changes that have occurred since the time of the acquisition or publication of the IRP.[23] This methodology is best applied under the "IRP Methodology." Under published rates, the values during periods

[23] Such changes can include load changes, new committed resources and contracts, fuel prices, and major changes to the wholesale marketplace (e.g., major additions or reductions to the regional resource stack).

of deficit are based not on the IRP or recent acquisitions, but instead on a surrogate avoided cost resource.

Q. What should QF developers be paid when the utility is surplus capacity?

A. The utility does not avoid any capacity costs by purchasing output from a QF during those times when the utility does not have a need for capacity. Because there is no need, and because no active capacity market exists in the northwest, the capacity value of QF power during surplus periods should be zero.

VI. QF DEVELOPERS SHOULD RECEIVE LOWER ENERGY PAYMENTS DURING UTILITY SURPLUS PERIODS TO REFLECT THE COSTS OF TRANSMITTING SURPLUS POWER TO MARKET

Q. Should QF developers be compensated for energy when the utility Integrated Resource Plan (IRP) shows a surplus?

A. I am not greatly concerned about providing a payment for energy when the IRP shows a utility energy surplus and no energy costs are actually avoided because a fairly liquid market for energy at the Mid-Columbia trading hub exists. As footnoted above, there may be a need to revisit this policy in the future due to changes in circumstances. However, if utilities are required to pay for unneeded energy, the avoided cost during the surplus period should reflect only the net value of QF surplus sold into the short-term wholesale marketplace.

Q. What is the net value of QF energy when the utility is surplus and does not avoid any costs by its purchase?

A. The value should reflect the market. For Avista in the northwest the principle market is at the Mid-Columbia trading hub. The energy rate should not exceed

1 the Mid-Columbia price net of those costs incurred to deliver the surplus power to that
2 point of delivery.

3 Delivery to the Mid-Columbia (i.e., through the use of transmission) is limited by
4 physical constraints. Avista has limited transfer capability, and surplus QF power sold at
5 the Mid-Columbia displaces other utility opportunities to sell existing surpluses of power
6 or to generate revenues from the resale of unused transmission to third parties.
7 Therefore, the price paid for QF power during surplus periods should be reduced by
8 Avista's transmission costs, which currently includes a $2.72 per kilowatt rate under
9 Avista's Open Access Transmission Tariff, and a defined three-percent energy loss
10 factor.

11 **Q. What is the total transmission discount when applied to base load,**
12 **wind, solar, biomass and drop canal hydroelectricity plants?**

13 A. Because transmission costs are not volumetric (i.e., based on the energy
14 generated), but instead on the level of reserved transmission capacity, the discount for
15 transmission costs varies depending on the capacity factor of the PURPA facility. The
16 following table estimates the discount for transmission costs based on an assumed
17 capacity factor for various QF technology types.

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Table 5 – Transmission Costs of Surplus QF Electricity (for a 1.0 MW Project)[24]

Line	Item	Base Load/ Biomass	Drop Canal Hydro	Wind	Solar	Note
1	QF Net Capacity Factor	92.0%	34.0%	33.0%	20.0%	Assumption
2	QF Average Energy (MWh/mo.)	672	248	241	146	Line 1 * 730 hrs in avg mo.
3	Transmission ($/kW-month)	2.72	2.72	2.72	2.72	Avista OATT
4	Transmission ($/MWh)	2.96	8.00	8.24	13.60	line 3 / line 1
5	Energy Rate ($/MWh)	45.45	45.45	45.45	45.45	Table 4, line 8
6	Losses	3.0%	3.0%	3.0%	3.0%	Avista OATT
7	Losses ($/MWh)[1]	1.36	1.36	1.36	1.36	line 5 * line 6
8	**Total Re-Marketing Costs**	**4.32**	**9.36**	**9.61**	**14.96**	line 4 + line 7
9	**As % of Energy Rate**	**9.5%**	**20.6%**	**21.1%**	**32.9%**	line 8 / line 5

The table explains that the average cost of delivering surplus energy is dependent on the capacity factor of the QF resource. Drop canal hydro and wind have a discount that is approximately twice that of resources operating in more base-load configurations. Their discount is similar because their capacity factor is similar. Solar, due to its even lower capacity factor, has a cost approximately three times that of base load generation.

Q. Should the net energy rate during surplus periods be reduced by the full transmission rate? In other words, is it possible that the utility will have surplus transmission from its marketing operations that could be used to transmit surplus QF power to market without cost?

A. Yes, the rate should be reduced by the transmission rate. It is possible that the merchant side of Avista's business might have surplus transmission capacity rights from time to time. However, this transmission has value to customers as it can be resold by Avista's transmission group to third parties. Reserving transmission for the purpose of moving QF power to market would reduce those transmission revenues. Further, losses associated with transmitting power to the Mid-Columbia hub exist, irrespective of the assumed cost of the transmission reservation.

[24] Values shown are for a 1 MW facility.

Q. Do you have any other observations that supporting your position that surplus QF energy be discounted for the full cost of transmission?

A. Yes. In 2006, FERC issued Order No. 688, reiterating its 1995 finding "that determinations of the avoided-cost rate must take into account all alternative sources including third-party suppliers and an electric utility does not pay for electric energy it does not need."[25] Accordingly, the Commission could decide that QF developers should receive no payments when the utility is surplus.

Additionally, current short-term PURPA rates recognize the impacts of market delivery costs. Any PURPA power purchased this way receives a payment equal to 85% of the Mid-Columbia index price. The reduction is an attempt to cover costs associated with delivering surplus energy to the market. It is therefore reasonable to protect customers against transmission costs when accepting surplus energy.

VII. PURPA CONTRACTS SHOULD NOT BE EXECUTED EARLIER THAN FIVE YEARS BEFORE COMMERCIAL OPERATION; RATES SHOULD NOT BE SET MORE THAN TWO YEARS PRIOR

Q. Should the ability of the QF developer to sign a PURPA contract ahead of scheduled commercial operation be limited?

A. Yes. The utility should not be expected to enter into a contract more than five years ahead of expected deliveries. I would prefer to limit contracting to two years; however, offering PURPA contracts with deliveries too few years into the future would limit developer opportunities to receive a capacity payment in the early years of the

[25] New PURPA Section 210(m) Regulations Applicable to Small Power Production and Cogeneration Facilities, 117 FERC ¶ 61,078 (2006) ("Order No. 688") (emphasis added); *see also* Southern California Edison Company and San Diego Gas & Electric Company, 70 FERC ¶ 61,215 at 61,677-78, reconsideration denied, 71 FERC ¶ 61,269 at 62,078 (1995).

contract. By committing itself to deliveries further into the future, the QF developer will be more likely to receive compensation for both energy and capacity.

Q. Should the prices be set in a contract with delivery occurring as far as five years into the future?

A. No. I recommend that prices be locked in no sooner than two years ahead of commercial operation. Too many things affecting price can change over a five-year term, both for the QF developer and the utility. This said, it would not be unreasonable for the utility to provide estimates over time of the then-current PURPA rates so that the QF developer would be apprised of the value of its future output.

VIII. PURPA CONTRACTS MUST HAVE MEANINGFUL LIQUIDATED DAMAGE AND TERMINATION PROVISIONS

Q. Do you support the continued inclusion of liquidated damages provisions in PURPA contracts?

A. Yes. Liquidated damages provisions, including adequate security to ensure payment of liquidated damages if necessary, are one of two key protections a utility must have with any developer who might otherwise not exercise their "put option" in the absence of an obligation on the part of the QF to perform. Once a PURPA contract is executed by the parties it becomes a firm contract in the utility's resource stack and, as such, the proposed QF resource postpones the development of other resource alternatives; in other words, the contract then allows and obligates the Company to avoid the costs associated with investing in its system to ensure reliable electricity service. To the extent the PURPA developer does not honor its contract commitments the utility ends up at the last moment having to procure other resources, potentially at higher cost. In the absence of meaningful liquidated damages, the QF developer has a free option to either honor its

1 contractual commitment where the avoided cost rate under the contract (agreed to years
2 before commercial operation) is greater than its alternatives at the time of commercial
3 operation, break its commitment and sell to a 3rd party if it can secure a higher price, or
4 simply cease development where market conditions have changed.

5 **Q. At what level should the Commission set the delay liquidated damages**
6 **deposit?**

7 A. There is precedent in recent Idaho PURPA contracts for a $45 per kilowatt
8 deposit based on installed capacity. This deposit provides recourse to the utility where
9 the QF developer does not build its resource as contractually agreed. I recommend that
10 this level be the minimum required in all PURPA contracts.

11 **Q. You stated that liquidated damages provisions are one of two key**
12 **protections that utilities need to protect against developers using PURPA as a**
13 **speculative put option. What is the second key protection?**

14 A. The second key protection is meaningful termination rights if the QF fails
15 to achieve commercial operation within the timeframes established in the PURPA
16 contract.

17 **Q. What are the termination provisions you envision as part of a PURPA**
18 **contract?**

19 A. Liquidated damage provisions by themselves work well in a market where
20 prices are rising. The QF developer has an incentive to bring its project online because if
21 it does not, damages will be based on the difference between the higher market price of
22 replacement power and the lower PURPA contract price. This payment is backed by the
23 liquidated damages security.

In a period of falling prices, however, liquidated damages are not assessed because market prices are lower than the contract price. The developer in this case might decide to postpone construction until prices rise. The utility meanwhile has to decide how to reliably fill the deficit left by a non-performing PURPA contract and is exposed to supply risk and future price increases.

To ensure QF developer obligations are honored, each PURPA contract should have a termination clause enabling the utility to terminate 180 days beyond the committed online date in the contract. This simple provision will put all QF developers on notice that their failure to honor PURPA contract obligations will result in contract termination.

Q. When should the liquidated damages deposit be required of the QF developer?

A. Recent FERC rulings highlight the risk of a PURPA contract constituting a legally enforceable obligation on the utility. This obligation needs to go both ways to ensure both parties honor their commitments. The best way to ensure a level playing field is to require the QF developer to post the liquidated damages deposit at the time that the legally enforceable obligation arises—i.e., when the utility has tendered a contract and the QF developer executes and returns the tendered contract obligating the utility to purchase contract output. Absent this provision, the utility has the potential to be subject to a legally enforceable obligation without recourse.

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IX. SAR GAS PRICES SHOULD BE UPDATED ANNUALLY USING THE ENERGY INFORMATION ADMINISTRATION'S ANNUAL ENERGY OUTLOOK

Q. Do you have any thoughts related to the present SAR natural gas price update cycle?

A. Yes. Natural gas is the single largest component of the SAR price calculation. While parties to various PURPA proceedings before this Commission have struggled to find a fair and timely source for estimating future natural gas prices, they generally agreed that the forecast should be from a public data source. Presently the price is tied to NPCC's work; however, this forecast is not updated with regularity and there is no guarantee that the forecast will be updated between its once-every-five-years Power Plan. Another source should be used.

Q. Do you have a recommended source for an annual update of the natural gas prices?

Yes. A better alternative is the Energy Information Administration's ("EIA") Annual Energy Outlook report. This federal government source is published annually and would provide a publicly-available forecast unbiased by anyone with vested interest in PURPA.

X. THE COMMISSION SHOULD NOT DETERMINE RECS OWNERSHIP IN THIS DOCKET

Q. Is Avista taking any position on Renewable Energy Credits (RECs) in this proceeding?

A. Avista believes this proceeding should be limited to the SAR and IRP Methodologies, and Avista therefore has limited its testimony accordingly.

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1 **Q. Does this conclude your direct-filed testimony?**

2 A. Yes.

CERTIFICATE OF SERVICE

I hereby certify that on this 30th day of January 2012, true and correct copies of the foregoing Direct Testimony of Clint Kalich were delivered to the following persons via Email (unless otherwise indicated).

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