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MISSOURI PUBLIC SERVICE COMMISSION

UTILITY SERVICES DIVISION

REBUTTAL TESTIMONY

OF

MARK L. OLIGSCHLAEGER

AQUILA, INC. D/B/A

AQUILA NETWORKS MPS-ELECTRIC

FILED²

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MARK L. OLIGSCHLAEGER
AQUILA, INC.
d/b/a AQUILA NETWORKS-MPS-ELECTRIC
CASE NOS. ER-2004-0034

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1 ARIES UNIT

2 Q. Has the Company made an adjustment to annualize the capacity charges
3 associated with MPS' purchase of power from the Aries Generating Unit?

4 A. Yes, it has. Company witness Starkebaum sponsors Aquila/UtiliCorp's
5 adjustment to annualize capacity charges associated with MPS purchased power agreements
6 (PPAs) at page 12 of her direct testimony. She states that the Company's adjustment includes
7 an annualization of Aries capacity charges.

8 A general description of the Aries PPA can be found on pages 7-8 of Company
9 witness Boehm's direct testimony.

10 Q. What level of capacity charges associated with the Aries unit has
11 Aquila/UtiliCorp included in its case?

12 A. The Company has reflected an annualized level of \$27.66 million.

13 Q. Does the Staff agree that \$27.66 million is an appropriate level to include in
14 rates for Aries capacity charges?

15 Q. No. Because MPS is purchasing power from the Aries unit through an
16 affiliated entity (Merchant Energy Partners – Pleasant Hill, or MEPPH), the Staff believes it is
17 appropriate to price the capacity from the Aries unit on a "lower of cost or market" basis.
18 Because the cost of the Aries capacity to MPS's affiliated supplier is less than the market
19 value paid by MPS for that power, MPS's rates should reflect only the cost to Aquila of the
20 Aries unit capacity. The quantification of this adjustment, and a more detailed explanation for
21 its rationale, can be found in my direct testimony in this proceeding.

22 Q. Why did Aquila/UtiliCorp make the decision for its MPS division to obtain
23 power through a purchased power agreement (PPA) with an affiliated entity?

1 A. The Staff believes this decision was made because the Company believed it
2 could earn higher profits by having a non-regulated affiliated entity construct a power plant
3 and sell power to MPS through a PPA, than having MPS construct the power plant for itself.

4 Q. Generally, what are an electric utility's options for obtaining additional power
5 to meet load growth or to replace existing power sources?

6 A. Generally, electric utilities have the option of either building their own
7 generating units to provide power for their customers or purchasing a portion of the output of
8 a generating unit owned by another electric provider.

9 Historically, when an electric utility builds its own generating unit, it typically intends
10 to use most of the power generated by that unit for the utility's native load customers. Some
11 of the unit's output may be sold to neighboring utilities to meet their power needs, and excess
12 energy during non-peak periods may also be sold to utilities in the interchange market. For
13 ratemaking purposes, this Commission has placed in rate base the net original cost of
14 constructing utility-owned units, and allowed a return on that amount in setting rates for those
15 utilities. Depreciation expense is booked to charge the cost of the units to expense on the
16 utility's income statement ratably over time. This allows the utility to earn a return "on" its
17 investment in rate base, and to recover a return "of" the investment through depreciation.

18 Alternatively, if a utility does not wish to construct and own generating units, it may
19 choose to either purchase capacity from a portion of the power produced by a generating unit
20 owned by another entity, or acquire power from a utility which has purchased power from
21 another entity – a "purchase for resale" transaction. In this case, the utility buying the power
22 is charged a price for that power reflecting both the capital costs of the unit producing the
23 power (the capacity or demand charge), and the incremental price of generating that power

1 (the energy charge). However, the entire amount paid by the purchasing utility for its share of
2 power is typically charged to purchased power expense on its books.

3 Another potential difference between ownership of a power plant, and purchasing
4 power from an outside entity is the term of the commitment. When a utility builds a power
5 plant, normally its intends to have the plant provide power for native load customers over the
6 useful life of the plant (generally 35-40 years or more). In contrast, agreements to purchase
7 power may be either short-term (i.e., one to five years) or long-term (20 years or more).

8 Q. When a utility builds generation to serve native load customers, is utility
9 ownership of that plant the only option available for that utility?

10 A. No. A utility choosing to build generation has the option of constructing the
11 unit, selling it to a third party, and then leasing the unit back from the new owner. The lease
12 payments charged by the new owner would again be based on the capital costs of the leased
13 unit, as well as the incremental cost of producing energy from the plant. The utility taking
14 power from the leased unit would charge the lease payments to lease expense on its books.

15 Q. When a utility takes power from a leased plant, as opposed to owning the
16 plant, how would the amount of the lease payments compare to the amount of rate recovery
17 the utility would receive from placing the unit in question in rate base?

18 A. Conceptually, the amounts should be similar, as both rate recovery of lease
19 expense and rate recovery of amounts associated with placing generating plants in rate base
20 are premised upon recovery of the capital and expense components of producing power,
21 which will be identical whether the unit is owned or leased. However, there usually are some
22 differences between the method by which lease payments are calculated for rate purposes and
23 how revenue requirement is calculated for generating plants included in rate base. Because

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1 the return on rate base component of power plant costs is calculated on the undepreciated
2 component of the plant costs at a point in time, this results in declining cost recovery over
3 time as the undepreciated amount of plant costs declines over time. In contrast, lease
4 payments are normally calculated on a levelized basis; that is, calculating the total return on
5 and of capital costs over a unit's life and spreading that amount equally over the life of the
6 lease. In addition, a lease term may not be the same as the expected life of the generating unit
7 put into rate base and, therefore, the capital cost recovery component of the lease payment
8 may not be the same as the revenue requirement for the unit that would be reflected in rates if
9 the unit were afforded rate base treatment.

10 Q. Does Aquila/UtiliCorp own or lease the Aries unit?

11 A. Yes. Aquila/UtiliCorp leases the Aries unit. As discussed in my direct
12 testimony, Aquila/UtiliCorp has chosen to provide the title to the Aries unit to Cass County,
13 Missouri, and then lease the plant from Cass County.

14 Q. Has MPS obtained power in the past through leasing of generating units?

15 A. Yes. MPS, while it has constructed generating units at its Greenwood and
16 Ralph Green locations in the past, chose to sell those units to third parties and then obtain
17 power from the plants through long-term lease arrangements.

18 Q. Why would a utility choose to lease a generating unit rather than own it
19 directly?

20 A. In the mid to late-1970s, when MPS chose to lease the Greenwood and Ralph
21 Green generating units, it is the Staff's understanding that MPS took that course of action
22 because it was experiencing financial difficulties at that time, and did not want to reflect
23 additional debt on its balance sheet associated with ownership of these units. Today, a utility

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1 may choose to enter into a leasing arrangement because it expects to achieve a higher return
2 associated with its generating plant investment through leasing the plant rather than having
3 the cost of the unit reflected in rate base. In that case, a utility may believe that it could
4 achieve greater profits from the unit if it was unregulated rather than be held to the regulated
5 rates of return authorized by public utility commissions. As will be discussed later in this
6 testimony, the desire for higher returns is the rationale for Aquila/UtiliCorp's decision to lease
7 the new Aries unit and this arrangement is an abuse of affiliate relationships.

8 Q. Has Aquila/UtiliCorp provided any information to justify its choice to
9 purchase generating capacity through a PPA with an affiliated entity rather than building its
10 own generating unit?

11 A. Yes. Case No. EM-99-369 was Aquila/UtiliCorp's application for the
12 Commission to make certain determinations required under the Public Utilities Holding
13 Company Act of 1935 respecting the contract between MPS and MEPPH for supply of power
14 from the Aries unit. In that proceeding, Aquila/UtiliCorp provided the Staff an analysis that
15 purports to demonstrate that the costs to MPS of entering into a five-year lease to obtain
16 power is less expensive than MPS owning the unit and rate basing it, over the five-year term
17 of the lease.

18 Q. From MPS's perspective, why might obtaining power through a PPA be more
19 economical than including the unit in rate base?

20 A. There are two basic reasons why a PPA might show a cost advantage. First, as
21 previously discussed, lease payments are typically based on levelized recovery of capital
22 costs, as opposed to the front-loaded recovery of the return component of the generating unit
23 caused by rate base treatment. This is also typical for the capacity cost recovery in a PPA.

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1 Second, the purchased power agreement MPS entered into calls for the Company to pay for
2 500 MW of power during peak periods, but a reduced amount of power during non-peak
3 periods. Rate base treatment would result in MPS customers being responsible for the entire
4 cost of the plant.

5 Q. Because of these factors, wouldn't the MPS PPA inherently be less expensive
6 than rate basing the Aries unit?

7 A. Not necessarily.

8 In regard to levelized cost recovery of capital costs under a PPA, the levelized cost
9 should be calculated in such a way that customers would be indifferent between paying rates
10 based on the traditional declining cost rate base methodology, or rates based on levelized PPA
11 cost recovery, over the life of the unit in question.

12 Concerning the point that rate base treatment would mean the full cost of the Aries
13 unit would be reflected in customer rates, that cost would be offset under the normal
14 ratemaking process by the proceeds of interchange sales made from the Aries unit during off-
15 peak periods (i.e., MPS's ability to sell power during off-peak periods due to its reduced need
16 for power during that time). One would have to know the amount of projected interchange
17 sales, and the estimated proceeds from those sales before reaching a firm conclusion on
18 whether rate basing or leasing the unit would be more economical from a ratepayer viewpoint.

19 Q. Is the five-year period of the PPA an appropriate time frame in which to assess
20 the benefits of the PPA versus owning the Aries unit?

21 A. No. Because ownership of the unit has long-term consequences, with most
22 units having an expected useful life of 30 years or more, an evaluation of whether it is
23 economically better to own a unit or purchase power from it should extend far beyond an

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1 initial five-year lease period. In fact, use of this five-year period to justify the decision to
2 purchase power from the Aries unit is inherently biased against the ownership option; again,
3 because of the levelized capital cost recovery feature of PPA cost recovery.

4 Q. In the Staff's view, has MPS done an adequate job of justifying its decision to
5 purchase power from the Aries unit, as opposed to MPS owning the unit?

6 A. No.

7 Q. Did the Company seriously give consideration to the option of having MPS
8 build a generating unit to meet its need for power beginning in 2001?

9 A. No. In the Staff's notes of the interview of Mr. Frank DeBacker
10 (Aquila/UtiliCorp's Vice-President of Fuel and Purchased Power in 1998-1999) and
11 Mr. Robert Holzwarth (Aquila/UtiliCorp's Vice-President of Power Services in 1998-1999), it
12 is stated that Mr. DeBacker and Mr. Holzwarth were knowledgeable of a clear understanding
13 from the Company's management at the time the Aries decision was made that
14 Aquila/UtiliCorp's regulated electric divisions were not to construct power plants; and that
15 these divisions' power needs were to be met through short-term PPAs.

16 As mentioned in my direct testimony, Mr. DeBacker and Mr. Holzwarth were given
17 the opportunity to review the Staff's notes of the interview and make any corrections,
18 additions or clarifications in the response to Staff Data Request No. 548.

19 Q. Does the Staff have additional concerns with the Company's decision to lease
20 the Aries unit?

21 A. Yes. The Staff believes the short term of the PPA (five years) exposes MPS
22 customers to greater risks associated with future market based pricing of power than they
23 would if MPS owned the Aries unit.

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1 Q. Please explain in general terms the concept of "market-based pricing" of
2 power.

3 A. "Market-based" pricing of power represents charging customers for power they
4 use based upon a price determined in a competitive marketplace of buyers and sellers. This
5 contrasts with treatment of generating units afforded under traditional regulation, in which
6 customers are charged rates based upon the actual capital and operating costs associated with
7 the units that are dedicated to native load customers. The market price of power at any point
8 in time may be higher or lower than the actual "embedded" price of power charged to
9 customers in electric rates under current regulation.

10 Q. What factors would cause the market price of power to either be higher than or
11 lower than the embedded costs of power reflected in rates?

12 A. Because generating units are long-lived assets, customers are likely to pay the
13 capital costs associated with any particular unit for an extended period of time (i.e., 30-40
14 years). If the cost of generating power from newer units and power generation technologies is
15 declining over time compared to the embedded cost of a utility's existing generating units,
16 then the market price of power will be less than that utility's embedded generating costs.
17 Alternatively, if the cost of generation from new units is increasing relative to the embedded
18 cost of generation for a utility, then the market price of power will be greater than that
19 utility's embedded generation costs. Accordingly, customers are not inherently benefited or
20 harmed by the introduction of market-based pricing of electricity. However, customers are
21 exposed to greater risk under market-based generation pricing.

22 Q. Why is market-based pricing riskier from a customer perspective?

1 A. It is riskier because customers will face more volatility in rates for power under
2 market-based pricing schemes than under the traditional embedded cost regulatory pricing
3 approach. As previously discussed, once a generating unit is operational and included in a
4 utility's rate base, the capital cost component of that unit's cost that is reflected in rates will
5 be highly predictable over the life of the unit. In contrast, the capital cost component of
6 market based electricity prices will be subject to frequent fluctuation based on trends in the
7 generation marketplace.

8 To use an example, if a utility provides electricity to its customers from one generating
9 unit only, the capital cost portion of electricity from that unit will be largely fixed in advance
10 over the life of the unit for 30 or 40 years, or more. Though rates charged to customers for
11 the capital costs of that unit may change over time, due to the "declining-cost" nature of
12 capital recovery in rates, those changes are highly predictable. In contrast, the capital cost
13 component of that utility's generation rates might be subject to material and unanticipated
14 changes on a frequent basis, if rates to its customers are based upon market prices for
15 generation.

16 For this reason, utility customers inherently face more risk of unexpected pricing
17 changes when market prices determine the rates they pay for electric service, as opposed to
18 the embedded costs of the generating units serving them.

19 Q. Please explain how MPS's contract to obtain power from the Aries unit is an
20 example of market-based pricing of power.

21 A. While the Aries unit is expected to have a lengthy life typical of a generating
22 unit, the contract only obligates Aries' owners to provide power to MPS for a five-year
23 period. At the end of the five years, MPS must either reach a new agreement with the Aries

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1 unit's owners to obtain additional power, or replace the power it obtained from the Aries unit
2 with another source. While the Aries owners may choose to again bid to supply power to
3 MPS customers when the five-year term of the current agreement has expired, they are not
4 obligated to do so. Even if power is continues to be supplied to MPS through another Aries
5 PPA after the five-year term of the initial PPA has expired, MPS customers will still face the
6 risk of changes in the market price of power in the new contract. If a new five-year PPA with
7 the Aries unit is agreed to starting in 2005, then MPS' customers will face the same risks five
8 years later in 2010.

9 Q. Has there a general trend towards greater market pricing of electric power in
10 this country in the recent past?

11 A. Yes, though generally this trend is tied to overall electric restructuring efforts
12 in various jurisdictions. In other words, those jurisdictions that have chosen to allow
13 customers greater choice in the selection of their electricity provider as a necessary
14 consequence also allow customers greater exposure to market pricing for generation service.
15 Whether electric restructuring is a worthy goal for pursuit is, of course, a policy judgment to
16 be made by legislatures and regulatory bodies. The Staff believes that neither the
17 Commission nor the Missouri Legislature has established a policy encouraging either electric
18 restructuring or greater market pricing of power to native load customers in Missouri.

19 Changes in the electric industry in recent years related to such factors as California
20 restructuring difficulties, the Enron bankruptcy and the financial problems of electric bulk
21 energy marketers have led to a significant slow down in electric restructuring initiatives.
22 Accordingly, the trend towards greater use of market pricing of power has also recently
23 decelerated as well.

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1 Q. Do electric utilities benefit from market-based pricing of generation service?

2 A. Electric utilities can conceivably achieve higher profitability levels charging
3 market-based rates compared to traditional embedded ratemaking, when the generation
4 services are performed by non-regulated affiliates providing capacity power to the regulated
5 entity under some form of contract arrangement, such as the case with the Aries PPA. Again,
6 this potential benefit depends upon the long-term trend in market prices for power compared
7 with the embedded cost of power production.

8 Q. Has Aquila/UtiliCorp undertaken a policy in the past of attempting to move
9 toward market pricing of generation?

10 A. Yes. Several years ago, the Company had the opportunity to place its
11 Greenwood Units 1 and 2 in rate base upon the expiration of the long-term lease arrangements
12 it had in place for the two units in the mid- to late-1970s. However, when Aquila/UtiliCorp
13 exercised its option to purchase these units, it chose to place them in a non-regulated
14 subsidiary, to enter into new leasing arrangements with the affiliated entity (MPS), and to
15 continue to obtain power from these units for MPS customers at a new, and higher, lease rate.
16 The Staff's concerns regarding this situation with the Greenwood units were discussed in
17 more detail in the direct testimony of Staff witness Featherstone in Case No. ER-2001-672.

18 The Staff believes Aquila/UtiliCorp has attempted to implement a policy of no longer
19 including in rate base the generating units it constructs to provide electric power for its native
20 load customers in its regulated divisions. For example, the Company made an attempt in Case
21 No. EM-97-395 to have all of its existing MPS regulated generating units placed in an
22 unregulated EWG. (The case was later withdrawn.) Aquila/UtiliCorp's proposals in Case
23 No. EM-97-395, the recent history of the Greenwood units and the Company's decisions

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1 regarding the Aries unit all demonstrate this policy of attempting to move generation
2 resources to Aquila/UtiliCorp's non-regulated side. Such a policy raises concerns regarding
3 affiliate abuse.

4 Q. Why has Aquila/UtiliCorp moved towards market-based pricing of power?

5 A. Based upon its response to Staff Data Request No. 365 in Case No. ER-2001-
6 672, the Company implemented this policy to allow it to achieve greater profit levels. The
7 response to Staff DR No.365 states, "[t]he Company believes that the current regulatory
8 climate does not warrant the business risks associated with constructing and owning rate-
9 based generating plants". The Staff interprets this statement to mean that Aquila/UtiliCorp
10 perceived at the time of this response that current return on equity levels earned on rate base
11 investments were inadequate, and that greater returns could be garnered through the lease of
12 power plants by affiliates and the purchase of power from these affiliates at "market" rates.
13 This policy of moving generation from the regulated utility to the non-regulated affiliate and
14 charging the utility a higher price is an abuse of the affiliate relationship.

15 Q. All other things being equal, if the Company can earn greater returns on its
16 generation investment by selling power to customers at market rates, what would be the
17 impact on MPS's customers?

18 A. All other things being equal, this means Aquila/UtiliCorp's native load MPS
19 customers over the long-term would pay higher rates related to "market-based" PPAs for
20 purchased power than they would pay if MPS's rates were based on embedded cost
21 ratemaking for those units.

22 Q. Is it possible at this time to determine whether this Aquila/UtiliCorp policy of
23 not placing new generating units in rate base was in the best interest of MPS ratepayers?

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1 A. Any such conclusion cannot be reached in the absence of a study comparing
2 the benefits and risks of direct ownership of units by MPS to obtaining power through lease
3 arrangements and PPAs. However, there are a number of indications that Aquila/UtiliCorp
4 expected the future price of power to increase, at least in the short-term; at the time the Aries
5 decision was made. If the Company's expectations are correct, the decision to purchase power
6 from the Aries unit as opposed to ownership of the unit by MPS may not be in the best
7 interest of MPS customers.

8 Q. What indications are you referring to?

9 A. The above answer is based on the following points:

10 1.) The Staff is aware of a number of power price forecasts utilized by the
11 Company that showed an expectation of sharply higher power prices through time.

12 2.) The market cost of replacing power obtained through a lease of the
13 Greenwood Units 1 and 2 several years ago was in excess of the prior leased cost, as
14 well as in excess of the cost of power from these units if these units were included in
15 rate base.

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20 Each of these points will be addressed in more detail below.

21 Q. What is your basis for asserting that the Staff has reviewed Company power
22 price forecasts that show significantly higher power prices into the future?

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1 A. In its review of the Aries PPA issue in the last MPS electric rate proceeding in
2 Missouri (Case No. ER-2001-672), as well as the instant case, the Staff has become aware of
3 the existence of several power price forecasts prepared by Aquila/UtiliCorp that indicated
4 sharply higher market prices of power were expected in future years. These forecasts were
5 prepared in the period of the late 1990s to the early years of this decade.

6 Q. What is the significance of these power price forecasts?

7 A. If a regulated utility expects escalating power prices into the future, it would
8 seem to be logical for that utility to hedge against higher power prices by owning and
9 controlling its own generating units, as opposed to relying on short-term PPAs and exposing
10 your customers to the risk of frequent power price increases.

11 Q. What was the situation concerning the price of power MPS is obtaining from
12 Greenwood Units 1 and 2?

13 A. As previously mentioned, upon the expiration of the long-term leases from
14 which MPS formerly obtained power from these units, Aquila/UtiliCorp chose to purchase
15 these units from the owners, place the units in an unregulated subsidiary, and then enter into a
16 new lease for the supply of power to MPS customers. The new lease costs were:
17 (1) substantially higher than the cost of power to MPS from these units under the recently
18 expired lease; and (2) substantially higher than the cost of power from these units if those
19 costs had been based upon traditional rate base treatment of those units

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Q. Does the fact that a utility decides to place ownership of generating facilities in an unregulated affiliate necessarily mean that the unregulated affiliate must charge the affiliated regulated entity a market price for power?

A. No, such affiliate abuse is not necessary. This is demonstrated by the Kansas City Power & Light Company (KCPL) Application for Commission approval of its corporate restructuring, docketed as Case No. EM-2001-464. In that case, KCPL received permission to form a holding company named Great Plains Energy, Incorporated (GPE). KCPL (the regulated utility) will retain all of its existing generating assets. Under the holding company structure, GPE proposed to place its future generating needs in an unregulated affiliate company, Great Plains Power, Inc. (GPP). However, the Stipulation and Agreement in Case No. EM-2001-464 called for any power sold to KCPL from certain generating units owned by GPP in the future would be sold at cost-based rates, so that the cost of power paid by KCPL would be equivalent to the costs paid by customers under traditional cost-of-service based rates. The Commission approved this Stipulation and Agreement, using the following language:

In January of 2001, KCPL entered into a binding memorandum of understanding with General Electric Company under which KCPL may lease or purchase up to five combustion turbine generating units. Each of these units has a generating capacity of 77 MW. These turbines will not be completed until 2003. If the proposed reorganization is approved, KCPL anticipates seeking Commission approval to transfer

1 its rights under the memorandum of understanding to GPP. KCPL
2 anticipates that it will need an additional 231 MW of generation
3 capacity in the next three years, that is, the generating capacity of three
4 of the five combustion turbines. KCPL currently purchases less than
5 five percent of its energy needs on the open market. If the proposed
6 reorganization is approved, KCPL may enter into a cost-based purchase
7 supply agreement with GPP to acquire this additional capacity. Such a
8 cost-based purchase supply agreement would provide power at a cost to
9 ratepayers identical to costs under traditional cost-of-service based
10 rates. The cost of power generated by a combustion turbine owned by
11 GPP would be essentially identical to the cost of power generated by a
12 combustion turbine owned directly by KCPL.

13 Order Approving Stipulation and Agreement and Closing Case, pp. 7-8.

14 Q. What is the Staff's overall policy recommendation in this proceeding regarding
15 the Aries unit?

16 A. The Staff has seen no evidence that Aquila/UtiliCorp has ever performed an
17 adequate analysis to compare the long-term cost of direct ownership of the Aries unit with the
18 cost of obtaining power from that plant through short-term PPAs. What evidence exists at
19 this point does indicate, however, that the Company has expected and still expects the price of
20 power in the marketplace to increase over time. If that is true, then MPS customers may have
21 been better off being able to utilize Aries power over its expected useful life as a Commission
22 regulated asset, rather than periodically having to obtain higher priced power from sources
23 elsewhere, or by paying for power from the Aries unit periodically "marked-up" to reflect
24 current market pricing.

25 The Company is currently in the process of receiving and evaluating bids concerning
26 its power needs subsequent to the expiration of the current Aries unit PPA. At this time, the
27 Staff recommends that the Commission order Aquila/UtiliCorp to explicitly consider MPS's
28 ownership of a generating unit (and, consequently, rate base treatment of the unit) as a
29 potential source of power beyond 2005, and as an alternative to continued receipt of power

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1 through affiliated lease arrangements and short-term affiliated PPAs. Such an analysis should
2 be at least as detailed as that which is addressed in the Commission's suspended electric
3 utility resource planning rules, 4 CSR 240-22.010-.080. The analysis should also be of a
4 long-term nature, in order to fully and fairly assess the benefits and detriments of MPS's
5 options for obtaining future capacity, including utility ownership of power plants. Only if
6 Aquila/UtiliCorp is ordered to do this will the Commission be able to adequately review and
7 evaluate in future rate proceedings the necessary evidence as to whether MPS is seeking
8 recovery of an excessive level of expense to compensate it for power provided to its
9 customers.

10 Q. Has the amount of the Staff's proposed adjustment for test year Aries capacity
11 charges changed since the filing of the Staff's direct testimony?

12 A. No. The Company has provided the Staff with certain additional information
13 regarding Aries costs during the prehearing conference to this case. The Staff is still in the
14 process of evaluating this information. If this or other information leads the Staff to revise its
15 Aries adjustment amount, the Commission and the parties to this proceeding will be informed
16 of these changes promptly.

17 Q. Does this complete your rebuttal testimony?

18 A. Yes, it does.

Summary of Synergy Benefits, net of Costs to Achieve

UtiliCorp/Saint Joseph Light and Power

	(Dollars in Current 000's)					First Five Full Years					Years 6-10		Ten Full Years			
	2001	2002	2003	2004	2005	Total	Average Years 1-5	2006	2007	2008	2009	2010	Total	Average Years 6-10	Total	Average
I Operating Costs	<i>Current Dollars</i>															
1 Dispatching/Generation Savings <i>See I.1</i>	\$ 3,820	\$ 4,358	\$ 5,196	\$ 5,021	\$ 6,087	\$ 28,502	\$ 5,700	\$ 7,817	\$ 6,502	\$ 7,274	\$ 6,587	\$ 5,733	\$ 33,883	\$ 6,777	\$ 59,963	\$ 5,997
2 General & Administrative Savings <i>See I.2</i>	\$ 5,193	\$ 5,599	\$ 6,739	\$ 5,892	\$ 6,079	\$ 28,442	\$ 5,688	\$ 6,180	\$ 6,354	\$ 6,493	\$ 6,555	\$ 6,322	\$ 32,484	\$ 6,497	\$ 50,926	\$ 5,093
3 Distribution Savings	\$ 1,385	\$ 1,821	\$ 1,985	\$ 2,014	\$ 2,054	\$ 9,249	\$ 1,850	\$ 2,118	\$ 2,169	\$ 2,273	\$ 2,279	\$ 2,308	\$ 11,127	\$ 2,224	\$ 20,370	\$ 2,037
4 Transmission Savings	\$ 313	\$ 248	\$ 562	\$ 676	\$ 590	\$ 2,591	\$ 518	\$ 305	\$ 300	\$ 636	\$ 652	\$ 668	\$ 3,160	\$ 636	\$ 5,772	\$ 577
5 Conversion to UtiliCorp Benefits <i>See I.5</i>	\$ 1,998	\$ 3,022	\$ 2,975	\$ 3,401	\$ 3,628	\$ 15,021	\$ 3,004	\$ 3,876	\$ 4,152	\$ 4,454	\$ 4,726	\$ 5,003	\$ 22,213	\$ 4,443	\$ 27,234	\$ 2,723
6 Total O&M	\$ 12,709	\$ 15,348	\$ 16,437	\$ 17,894	\$ 18,937	\$ 61,385	\$ 12,277	\$ 20,594	\$ 19,777	\$ 21,079	\$ 20,670	\$ 20,561	\$ 102,862	\$ 20,576	\$ 184,767	\$ 18,477
II Capital Savings (Costs):																
1 Depr - Interconnect, SCADA/T&D <i>See II.1</i>	\$ (285)	\$ (230)	\$ (324)	\$ (318)	\$ (313)	\$ (1,570)	\$ (314)	\$ (307)	\$ (302)	\$ (286)	\$ (280)	\$ (320)	\$ (1,525)	\$ (306)	\$ (3,095)	\$ (312)
2 Amort of Transition/Transition Costs	\$ (1,506)	\$ (1,506)	\$ (1,509)	\$ (1,509)	\$ (1,509)	\$ (7,545)	\$ (1,509)	\$ (1,504)	\$ (1,504)	\$ (1,509)	\$ (1,506)	\$ (1,501)	\$ (7,537)	\$ (1,507)	\$ (15,082)	\$ (1,508)
3 Return on Interconnect, SCADA/T&D	\$ (806)	\$ (807)	\$ (841)	\$ (785)	\$ (731)	\$ (4,152)	\$ (830)	\$ (877)	\$ (824)	\$ (971)	\$ (916)	\$ (1,453)	\$ (7,854)	\$ (871)	\$ (7,006)	\$ (701)
4 Return on Transition/Transition Costs	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
5 Total Capital Savings (Costs):	\$ (2,696)	\$ (2,738)	\$ (2,674)	\$ (2,603)	\$ (2,563)	\$ (10,257)	\$ (2,053)	\$ (2,493)	\$ (2,435)	\$ (2,576)	\$ (2,318)	\$ (2,254)	\$ (11,918)	\$ (2,382)	\$ (25,163)	\$ (2,518)
III Total Synergies, net of Cost to Achieve	\$ 10,019	\$ 12,612	\$ 13,763	\$ 15,281	\$ 16,443	\$ 68,118	\$ 13,624	\$ 18,101	\$ 17,342	\$ 18,705	\$ 18,552	\$ 18,287	\$ 92,966	\$ 18,193	\$ 180,804	\$ 18,088
IV Enterprise Support Functions Allocated (In) Current Dollars																
1 S.J.P. Direct Costs transferred to ESF <i>See IV.2</i>	\$ 2,292	\$ 2,350	\$ 2,409	\$ 2,459	\$ 2,530	\$ 12,050	\$ 2,410	\$ 2,564	\$ 2,650	\$ 2,725	\$ 2,793	\$ 2,863	\$ 13,630	\$ 2,727	\$ 26,813	\$ 2,688
2 S.J.P. Direct Costs transferred to I&U	\$ 922	\$ 1,212	\$ 1,308	\$ 1,341	\$ 1,274	\$ 6,157	\$ 1,231	\$ 1,409	\$ 1,444	\$ 1,480	\$ 1,517	\$ 1,555	\$ 7,404	\$ 1,481	\$ 12,581	\$ 1,258
3 Support Functions Allocated (In)	\$ (12,376)	\$ (12,665)	\$ (13,002)	\$ (13,327)	\$ (13,663)	\$ (66,049)	\$ (13,210)	\$ (14,602)	\$ (14,352)	\$ (14,710)	\$ (15,078)	\$ (15,455)	\$ (73,997)	\$ (14,778)	\$ (156,645)	\$ (13,865)
4 Net Allocations (costs) savings to S.J.P.	\$ (8,161)	\$ (9,103)	\$ (9,285)	\$ (9,517)	\$ (9,759)	\$ (48,642)	\$ (9,738)	\$ (9,669)	\$ (10,249)	\$ (10,502)	\$ (10,768)	\$ (11,037)	\$ (52,592)	\$ (10,312)	\$ (95,407)	\$ (9,940)
V Total Synergies, net of Costs to Achieve and Allocated Costs	\$ 656	\$ 3,459	\$ 4,478	\$ 5,764	\$ 6,685	\$ 4,255	\$ 4,255	\$ 8,431	\$ 7,093	\$ 8,198	\$ 7,784	\$ 7,250	\$ 7,881	\$ 7,881	\$ 15,407	\$ 15,148
VI Premium Costs																
1 Return on Premium <i>See IV.1</i>	\$ (10,293)	\$ (9,841)	\$ (9,580)	\$ (9,418)	\$ (9,156)	\$ (48,309)	\$ (9,662)	\$ (8,826)	\$ (8,632)	\$ (8,371)	\$ (8,110)	\$ (7,842)	\$ (41,857)	\$ (8,371)	\$ (62,256)	\$ (8,026)
2 Amortization of premium	\$ (2,302)	\$ (2,302)	\$ (2,302)	\$ (2,302)	\$ (2,302)	\$ (11,610)	\$ (2,302)	\$ (2,302)	\$ (2,302)	\$ (2,302)	\$ (2,302)	\$ (2,302)	\$ (11,510)	\$ (2,302)	\$ (23,020)	\$ (2,302)
3 Refect non-tax deductibility of premium	\$ (1,535)	\$ (1,835)	\$ (1,535)	\$ (1,835)	\$ (1,535)	\$ (7,870)	\$ (1,535)	\$ (1,835)	\$ (1,835)	\$ (1,535)	\$ (1,535)	\$ (1,535)	\$ (7,870)	\$ (1,535)	\$ (15,740)	\$ (1,535)
4 Total Premium cost	\$ (14,129)	\$ (13,778)	\$ (13,519)	\$ (13,255)	\$ (12,693)	\$ (67,809)	\$ (13,615)	\$ (12,953)	\$ (12,475)	\$ (12,209)	\$ (11,948)	\$ (11,685)	\$ (61,341)	\$ (12,208)	\$ (109,622)	\$ (11,202)
VII S.J.P. share of premium costs	\$ (7,320)	\$ (6,839)	\$ (6,769)	\$ (6,827)	\$ (6,497)	\$ (6,768)	\$ (6,768)	\$ (6,346)	\$ (6,215)	\$ (6,104)	\$ (6,073)	\$ (6,042)	@50%	\$ (6,104)	\$ (6,104)	\$ (6,104)
VIII Synergies, net of 50% of premium (In) (Less VI)	\$ (6,463)	\$ (3,400)	\$ (2,283)	\$ (884)	\$ 192	\$ (2,503)	\$ (2,503)	\$ 1,734	\$ 889	\$ 2,094	\$ 1,811	\$ 1,388	\$ 1,577	\$ 1,577	\$ 1,577	\$ 1,577

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