Service Date: September 12, 1985

DEPARTMENT OF PUBLIC SERVICE REGULATION
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MONTANA

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IN THE MATTER Of The Commission's Investigation Of Electric Avoided Cost Rates.	)))	UTILITY DIVISION DOCKET NO. 84.10.64 ORDER NO. 5091b

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APPEARANCES

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BEFORE:

CLYDE JARVIS, Chairman
HOWARD ELLIS, Vice Chairman
JOHN DRISCOLL, Commissioner
TOM MONAHAN, Commissioner
DANNY OBERG, Commissioner

FINDINGS OF FACT

I. Introduction

A. Historic/Procedural Background

1. In 1978, the Public Utility Regulatory Policies Act (PURPA) was signed into law. Section 210 of PURPA directed the Federal Energy Regulatory Commission (FERC) to prescribe rules that encourage cogeneration and small power production facilities (hereafter, collectively referred to as qualifying facilities or QFs).

2. Section 210 set forth certain guidelines that must be followed when developing avoided cost prices including:

(1) Prices must be just and reasonable and in the public interest;

(2) Prices shall not be discriminatory to QFs; and,

(3) No price shall exceed the incremental cost to the utility of alternative electric power.

3. The Act defines incremental cost to mean, with respect to electric power purchased from QFs, the cost to the electric utility of the electric energy which, but for the purchase from such QFs, such utility would generate or purchase from another source.

4. In 1980, FERC prescribed rules and regulations implementing PURPA Section 210 (see 18 CFR Part 292 as published in the Federal Register/Vol 45, No. 56 March 20, 1980).

5. In June of 1981, this Commission adopted electric avoided cost rules that incorporated these rules by reference. (See ARM 38.5.1901 et seq.)

6. Also in 1981, legislation was enacted creating what has been referred to as Montana's "mini-PURPA," dealing with avoided cost prices for small power production facilities (this law was amended in the 1983 legislative session to include cogeneration facilities).

7. In 1982, this Commission issued an order in Docket No. 81.2.15 (the Commission's first avoided cost docket) adopting the base-peak method for computing avoided cost prices.

8. In 1983, this Commission issued an order in its second avoided cost docket (Docket No. 83.1.2), reaffirming the merits of using the base-peak method for computing avoided cost prices.

9. Two significant changes, however, were made in Docket No. 83.1.2: (1) a real carrying charge was adopted for annualizing capital costs; and (2) real and nominal levelized price options were tariffed. The result of these changes was that the value of QF power was tied to QF contract length: longer contracts resulted in higher avoided cost prices.

10. The present avoided cost docket was instituted with the primary objective of revisiting the "appropriate avoided cost methodology" issue (see the Procedural Order at Finding No. 3). That is, precise avoided cost calculations were not the objective of the testimony and hearing in this docket.

11. On December 10, 1984, this Commission issued Order No. 5091a, distinguishing between fully negotiated QF contracts and those that were still being negotiated. Qualifying facilities with fully-negotiated contracts would receive the avoided cost prices then in effect upon commencing production; these prices would not be subject to revision as a result of decisions in the present docket. Qualifying facilities without fully negotiated contracts faced the prospect of changed avoided cost prices, depending on the Commission's final decision in the present docket. The Procedural Order of January 17, 1985, set forth issues that all parties were requested to address.

12. In February of 1985, the Commission issued an order in Docket No. 84.10.64 that consolidated Docket Nos. 84.10.64 and 84.11.71 (the MPC general rate case). In March, an order

was issued in the same docket establishing procedural safeguards regarding testimony offered in Docket No. 84.11.71.

B. Purpose of Docket No. 84.10.64

13. As noted above, the present docket was initiated with the principle intent of revisiting the method(s) that should be used to compute avoided cost prices. The apparent need to revisit this issue arose from circumstances surrounding the Montana Power Company's load resource balance that was revealed in the Power Company's load resource balance that was revealed in the first Colstrip 3 docket (Docket No. 83.9.67). Rather than initiate a separate docket for each of the three utilities, it was the Commission's finding that one docket would most efficiently resolve the issue.

14. In previous avoided cost dockets the Commission adopted what is referred to as the "base-peak" approach to compute avoided cost prices. Previous reasons for using this approach were based on the resources included in each utility's resource plans, combined with the ease of implementation and simplicity. It appears, however, that this approach has not stood the test of time. What the base-peak approach appears to lack, as used by this Commission, is the ability and flexibility to adopt to changing load/resource balances.

15. As evident from the various parties' testimony in the present docket, there are potentially numerous conflicting objectives. From a public policy standpoint, the Commission finds that the ultimate objective must be to minimize the cost of generating electricity through the promotion of an efficient combination of cogeneration, small power production and conventional utility resources. While this ultimate objective is shared by the various parties in the docket, their respective methods by which it is achieved differ significantly.

16. In this order the Commission will discuss the various approaches used to compute avoided cost prices, the parties’ recommendations, and finally, the Commission’s decisions.

II. Methods to Compute Avoided Cost Prices

A. Avoided Cost Components

17. An attempt to define avoided costs is a first step in answering the question: "What costs are potentially avoidable?" In both electric retail rate cases and avoided cost dockets the range of relevant costs is set forth, followed by actual empirical estimates of the components.

18. The following table provides a functionalization and classification of potential avoided cost components. The three basic functions include: generation, transmission and distribution cost breakdowns. The three basic classifications include: energy (Kwh), demand (Kw), and customer cost breakdowns. It should be emphasized that the fact a cost is marginal or incremental does not mean it is avoidable. This point is discussed later this order.

Table 1
Potential Avoided Cost Components

	Function		
Classification	Generation (1)	Transmission (2)	Distribution (3)
(1) Energy (/kwh)	E_1	E_2	E_3
(2) Demand (/kw)	D_1	D_2	D_3
(3) Customer (/customer)	C_1	C_2	C_3

19. The Procedural Order in this docket requested comments on each of these potential cost components. However, in previous avoided cost dockets, prices have been based only upon values for variables "E1" and "D1", with the exception of a line loss adjustment.

20. Following an initial discussion on short-run and long-run costs, each of the approaches will be reviewed.

B. Short-Run Versus Long-Run Costs

21. The economic distinction between the short-run and the long-run suggests underlying cost differences. Further, businesses are described as operating in the short-run and planning for the long-run. This description suggests a utility may have a different recipe (production function) for producing power in the short-run than in the long-run. This is very likely the case given sunk fixed costs, changing technology, expectations of changing relative capital and fuel prices, and opportunities to purchase power.

22. In the short-run, a utility cannot change the stock of fixed capital resources used to generate power. In other words, a utility takes its existing generating resources as a given, and attempts to minimize the total variable costs (e.g., fuel expense and O&M) of meeting any and all loads by economically dispatching existing generation resources.

23. In the long-run, existing generation resources may be replaced or augmented. That is, the long-run is sufficiently long that all factors of production (e.g., fuel, capital investment labor/management) are variable: in the long-run, a utility attempts to minimize its total costs (fixed and variable) of power production.

24. These considerations form the basis for short-run marginal costs (SRMC) and long-run marginal costs (LRMC). There is a common belief that LRMCs always exceed SRMCs. This belief, however, is incorrect. There are many different short-run marginal cost curves (e.g., daily and yearly). SRMCs oscillate above and below LRMCs. In addition, one can speak of long-run projections of SRMCs. One economic justification for building baseload plants is when SRMCs are consistently higher than LRMCs.

C. <u>Avoided Cost Pricing Approaches</u>

25. Potential avoided cost components include those variables in Table 1 above. Of these cost components, only generation-related energy and demand (variables "E1" and "D1") will be discussed in this section. The other cost components are discussed in a later section. The cost approaches on which the Commission requested comments included:

1. Base-Peak

2. Peaker
3. Fuel Offset
4. Revenue Requirements (the slippage/perturbation or deferral approach)
5. Opportunity purchases
6. Opportunity sales
7. Federal power prices [e.g., 7(f)]
8. Electric retail rates
9. Competitive bidding process

26. In its testimony, the Montana Consumer Counsel's witness John Wilson (Exh. No. 14) discussed three long-run marginal cost approaches. Table 2 shows how these three approaches derive from the following formula:

"LRMC = $FC_B + VC_B = FC_P + VC_P$ " where,
LRMC = Long-run marginal costs
FC = Fixed Costs ($/kw)
VC = Variable Costs (cents/kwh)
B + P Subscripts = Base and Peak

Table 2

Equations for Three LRMC Approaches

LRMC Approach	Demand	Energy
Base-Peak	FC_P	$VC_B + (FC_B - FC_P)$
Peaker	FC_P	VC_P
Fuel Offset	$FC_B - (VC_P - VC_B)$	VC_P

Base-Peak Approach

27. The theoretic logic underlying the base-peak approach draws on the different functions of baseload and peakload resources. The base-peak approach reflects a major change from the "fixed-variable" method of cost allocation commonly used in the past. Whereas the "fixed-variable" cost allocation allocates fixed capacity costs to demand charges ($/kw) and variable costs to energy charges (cents/kwh), the base-peak approach recognizes the economic reason for which high capacity factor baseload generating plants are built, which is to provide energy rather than to meet the utility's peak loads. This is the so-called "fuel savings" argument.

28. In previous dockets the base-peak approach has been recommended for use in computing marginal costs by the following: (1) Montana Department of Natural Resources and Conservation; (2) Pacific Power and Light Company and (3) District XI Human Resource Council Inc.

29. In its orders in the first avoided cost docket, this Commission recognized that each utility's resource plans included various coal-fired generating plants. In an order of the second avoided cost docket, the Commission once again recognized a common denominator in each utility's resource plan, noting that on the horizon each included a baseload coal-fired generating plant.

30. Since the time of these two avoided cost dockets, however, resource additions planned by MPC and PP&L have significantly changed. While MDU's most recent resource plan includes coal-fired resources, PP&L's and MPC's recent resource plans exclude coal-fired resources. On the supply side, and for PP&L and MPC, this change in resource plans calls into question whether the Commission should continue to use coal plant costs to determine these utilities avoided costs. However, one is not restricted to using just baseload coal-fired resource costs in the base-peak approach.

Peaker Approach

31. The peaker approach features prices based on the fixed and variable costs of a marginal peaking unit such as a combustion turbine. In practice however, this approach relies upon marginal running costs (system lambda) for energy prices, and the marginal cost of additional peaking capacity for demand prices.

32. In the past, this Commission has adopted the peaker approach in developing marginal cost-based retail electric prices for both MDU (Docket No. 83.9.68) and MPC (Docket No. 80.4.2), based on both the Montana Consumer Counsel's and utility's recommendations. In the Commission's first avoided cost docket, Thomas M. Power, testifying on behalf of the Commission staff, also acknowledged the economic merit of the peaker approach.

33. It is worth noting that the FERC suggested two ways by which electric avoided cost prices could be computed, one of which is the peaker approach:

> The costs which an electric utility can avoid by making such purchases generally can be classified as "energy" costs or "capacity" costs. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours). They represent the cost of fuel, and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy; they consist primarily of the capital costs of facilities.
>
> If, by purchasing electric energy from a qualifying facility, a utility can reduce its energy costs or can avoid purchasing energy from another utility, the rate for a purchase from a qualifying facility is to be based on those energy costs which the utility can thereby avoid. Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg. 12216 (1980).
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> * * *
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> The Commission has added the term "incremental" to modify the costs which an electric utility would avoid as a result of making a purchase from a qualifying facility. Under the Principles of economic dispatch, utilities generally turn on last and turn off first their generating units with the highest running cost. At any given time, an economically dispatched utility can avoid operating its highest-cost units as a result of making a purchase from a qualifying facility. The utility's avoided incremental costs (and not average system costs) should be used to calculate avoided costs. With regard to capacity, if a purchase from a qualifying facility permits the utility to avoid the addition of new capacity, then the avoided cost of the new capacity and not the average embedded system cost of capacity should be used. Id.

Fuel-Offset Approach

34. The fuel-offset approach is the third LRMC method that may be derived from the formula discussed previously. Energy avoided costs are computed as they are in the peaker approach. The demand component, on the other hand, is based upon the capital cost of a baseload plant, less the fuel savings it enjoys when compared to a peaking unit.

35. The fuel offset was one method proposed by MPC in a recent docket as a means to compute marginal capacity costs. MDU proposed a method, similar to the fuel offset, for computing generation-related capacity costs in Docket No. 83.9.68.

Revenue Requirements Approach

36. The revenue requirements approach to computing avoided cost prices is the second approach the FERC discussed in its rules and regulations:

> One way of determining the avoided cost is to calculate the total (capacity and energy) costs that would be incurred by a utility to meet a specified demand in comparison to the cost that the utility would incur if it purchased energy or capacity or both from a qualifying facility to meet part of its demand, and supplied its remaining needs from its own facilities. The difference between these two figures would represent the utility's net avoided costs. In this case, the avoided costs are the excess of the total capacity and energy cost of the system developed in accordance with the utility's optimal capacity expansion plan, excluding the qualifying facility, over the total capacity and energy cost of the system (before payment to the qualifying facility) developed in accordance with the utility's optimal capacity expansion plan including the qualifying facility. Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg. 12216 (1980). (footnotes omitted)

37. The FERC's description, however, does not make clear how energy and capacity components would be derived from the utility's "net avoided cost" calculation. Avoided energy costs could be computed based on two production cost model runs. For example, one run would reflect the utility's optimal expansion plan (as FERC suggests); the second run could reflect 10MWs of free QF power or 10 MWs in load reduction. Avoided capacity costs could be computed by looking at the revenue savings that result from delaying construction of new resources due to the availability of 10 MWs of QF power.

38. This approach requires computer modeling capability. MPC has such capability, given its proposal in Docket No. 83.1.2 to compute avoided capacity costs based on the reduction in MPC's revenue requirements resulting from the acquisition of QF capacity. MDU, however, does not have such computing capability (See MDU response to PSC staff Data Request No. MDU-10i). PP&L, apparently has computer capability and supports the use of the revenue requirement approach (See PP&L response to PSC staff Data Request No. PP&L-10i).

Opportunity Purchases

39. The opportunity purchases concept is one that could be used in any of the approaches previously discussed. For example, either historic or forecasted opportunity purchases of energy could be in the utility's short-run economic dispatch analysis. If a short-run opportunity purchase of energy is cheaper than the utility's generation alternative, energy should be purchased. That is, opportunity purchases of energy should simply be reflected in calculations of variable running costs.

40. It should be noted that opportunity purchase prices affect avoided cost prices only if a utility plans to acquire such power. In other words, avoided cost prices derive from two factors. These two factors are supply and demand (this point is critical to the adoption of an avoided cost pricing approach).

Opportunity Sales

41. While the title suggests reference to nonfirm opportunities, a digression on the issue of long-term firm sales (e.g., the Black Hills Power and Light/PP&L Sale) is relevant. The Black Hills Power and Light/PP&L sale of Colstrip 3 is economically irrelevant in an avoided cost price determination. Similarly, if MPC sold Colstrip 4, the sales price is economically irrelevant to the determination of avoided cost prices.

42. Neither the FERC's, nor this Commission's rules make any specific reference to opportunity sales in developing avoided cost prices. In addition, one must ask: what would BHP&L or the purchaser of MPC's share of Colstrip 4 be willing to pay for one more KW or KWH? The demand side of the equation must be taken into account.

43. In a short-run context, opportunity sales are a relevant avoided cost price consideration. In terms of economic dispatch, off-system sales affect variable running costs.

44. In addition to the effect on running costs, if a utility is willing and able to sell QF power off-system, then such an opportunity sale should be factored into the avoided cost price. This is an example of an exchange where all parties are made better off. The exchange is relevant in both the short-and long-run. The Commission recognized the economic validity of opportunity costs in its 1984 Colstrip 3 rate structure order (Order No. 5051d).

Federal Power Prices

45. The Procedural Order requested comments on the economic merit of using BPA's 7(f) rate to determine avoided costs. The issues that arise around the use of this price include: (1) the FERC/PSC legal/administrative acceptance and (2) the economic rational of such a cost-based price. Each is discussed in turn.

46. First, the FERC/PSC avoided cost rules permit avoided cost prices to reflect purchased power prices. Some parties criticized this approach as being economically irrational, although that claim was challenged by the utilities.

Electric Retail Prices

47. The Procedural Order requested comments on equating avoided cost prices with electric retail rates. The benefits of such an idea appear to be the administrative ease of setting avoided cost prices. However, the costs may overwhelm the benefits, since retail prices may reflect costs that are not avoidable.

Competitive Bid

48. By including the notion of a competitive bid (CB) in the Procedural Order, the Commission had in mind a method by which the costs to both the economy and ratepayers would be minimized. This ground is not well trod and the Commission was exploring the economic merits of such a notion. The competitive bid notion will be discussed in greater detail later in this order.

III. The Parties' Recommended Avoided Cost Pricing Approaches

Montana-Dakota Utilities

49. Gary Paulsen testified for MDU, submitting direct (Exh No. 17) and rebuttal testimony (Exh. No. 18). In terms of policy, Paulsen claimed that the present avoided cost prices do not reflect MDU's avoided costs. As a result, the "ratepayer neutrality" objective is not achieved.

50. MDU proposed separate avoided cost prices for energy and capacity, and a metering charge. Energy-related avoided cost prices would reflect MDU's average running costs, based on a 1 MW decrement production cost modeling run (TR 327). The related avoided cost prices would reflect the Mid-Continent Area Power Pool's (MAPP) prices. These prices would vary based on contract length (less than/greater than 48 months); these prices would also only be available six (6) months per year (but, cf. TR 336). Paulsen proposed that metering-related charges be assessed QFs based on the phase of service. MDU also proposed that QFs larger than 100 kw in size negotiate prices with MDU.

51. In addition to the two contract-length based tariffs, Paulsen also proposed an "occasional power purchase" tariff. This tariff features a flat (no time differentiation) energy price, no capacity payments, and a metering charge. Under this proposal, MDU would limit to 600 kwh/month the purchases it would make from any QF (regardless of the QF's kw size).

52. In contrast to these proposals, Paulsen claimed that it is incorrect to use the MAPP Schedule "B" and "H" capacity prices in the base-peak approach (TR 213).

53. MDU's resource plan features a series of coal-plant additions, a possible combustion turbine, and MAPP purchases. Table 3 summarizes MDU's resource plan:

Table 3

MDU's Resource Additions

	Coal-Plants	Combustion-Turbine	MAPP
1985	Big Stone/Coyote[1]		Various Scheduled
1986	AVS II		Purchases[2]
1990		Generic CT[3]	
1996	AVS III[4]		

Montana Power Company

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1 MDU indicated it was pursuing a 21MW share of Minnesota Power’s Coyote Plant (TR 302).

2 MDU has proposed basing avoided cost capacity prices on certain MAPP schedule rates; assumedly, MDU plans to purchase power from these MAPP schedules (TR 325).

3 The development of a CT hinges on a Fuel Use Act exemption (TR 324).

4 MDU has no negotiated contract for AVS No. 3. other than the original letter of intent (TR 324).

54. Three witnesses presented MPC's avoided cost case including Tom Lovas (Direct--Exh. No. 19 and Rebuttal--Exh. No. 20), Richard Cromer (Direct--Exh. No. 21 and Rebuttal--Exh. No. 22) and Jack Haffey (Direct--Exh. No. 23).

55. Lovas supplied MPC's proposed method for computing avoided cost prices. The proposal reflects the importance of resource need (timing) and "ratepayer neutrality." Lovas noted that a proper avoided cost price would reflect the present value of revenue requirement savings based on the current resource plan. In contrast to this ideal, Lovas noted that the current levelized nominal avoided cost prices ignore resource timing and the dynamics of system load levels. The current method also overstates Colstrip 3 and 4 capital costs due to escalating historic costs.

56. In achieving the ideal basis for avoided cost prices, that being the present value of revenue requirement savings, Lovas proposed the same method tendered in the two previous avoided cost dockets (see Data Response MPSC No. 2-6 to the Commission Staff). As a result, the energy portion of the avoided cost price would reflect system running costs. The capacity portion of the avoided cost price would reflect the deferral value of capacity additions.

57. In Docket No. 83.1.2, MPC computed avoided energy costs based on two production cost modeling runs, a base run and a decrement run that assumed 10 MWs of zero-cost QF production. The capacity portion, in Docket No. 83.1.2, was computed based on the deferral value of MPC's resource plan.

58. In addition to this approach, Lovas agreed that the base-peak method could be used if certain hydro upgrades were substituted for baseload and peakload plants (TR 411).

59. MPC's resource plan is set forth in the following table:

Table 4

MPC's Resource Additions[1]

	Hydro Upgrades	QFS	Purchases
1985		Various QF Resources Come	
1987		Milltown online from	

[1] This is for "Base Case" generation additions only and derives from Table 9 of MPC's Projection of Electric Loads and Resources (see MCC Data Request of March 11, 1985 to MPC No. 1-1 in Docket No. 84.10.64).

		year 1985[2] to year 2008	
1989	See purchases		Purchased power may derive from numerous sources[3]

60. Finally, MPC proposed a cost tracking mechanism. This mechanism, a Power Cost and Credit Clause, involves semiannual filings to recover avoided cost and other expenses.

Pacific Power and Light

61. Four witnesses presented PP&L's avoided cost case including Dennis Steinberg (Direct--Exh. Nos. 1 and 2, and Rebuttal--Exh Nos. 8 and 9), William Wordley (Direct--Exh. Nos. 3 and 4, and Rebuttal--Exh. No. 10), Jerry Rust (Direct--Exh. Nos. 6 and 7, and Rebuttal--Exh. No. 11) and Tim Watson (Rebuttal--Exh. No. 12).

62. PP&L has split its future load/resource balance into two time periods. The first period runs from 1985 to 1993 and is one of resource sufficiency. The second period begins in 1993, and is one of resource deficiency. In either time period, PP&L's policy objective is to achieve ratepayer neutrality.

63. Steinberg supplied PP&L's proposed avoided cost price basis for the short-term period (resource sufficiency). Short-term energy-related avoided cost prices reflect the benefit of QF

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[2] QF resources in the amount of 3 average Mws are assumed on-line in 1985; by year 2008, 149 average MWS are assumed on line (ibid).

[3] Purchased power includes resources from: BPA (peak purchases), other utilities and seasonal exchanges (TR 400, 401). If purchases are not available, certain hydro upgrades will be pursued (Kerr, Thompson Falls, Ryan and development at Hebgen).

power production and are comprised of three parts: (1) system fuel costs (assuming a 10MW decrement production cost modeling run); (2) purchase power costs; and (3) nonfirm wholesale power revenues. This latter part is referred to as the "opportunity cost" portion of the proposal.

64. PP&L proposed to pay a capacity-related avoided cost price in the short term if a QF's power is reliable, dispatchable and flexible (TR 82, 83). Capacity payments may be levelized, but not earlier than seven years prior to a BPA power purchase.

65. In the long-term after 1993, PP&L proposed to base avoided cost prices on BPA's 7(f) rate. The energy and capacity portions would be split out 77 percent and 23 percent respectively (TR 41, 42). PP&L's Long-term -- beyond 1993 -- resource plans include cost-effective conservation measures and purchases from BPA's 7(f) rate.

Montana Consumer Counsel

66. John Wilson testified for the MCC, submitting direct (Exh. No. 14) and rebuttal testimony (Exh No. 15). The MCC set forth general policy concerns and surveyed the various analytical and conceptual bases of avoided cost prices. These concerns will be reviewed in turn, followed by the MCC's comments on other parties' avoided cost price proposals.

67. MCC's policy concerns include: (1) ratepayer neutrality: a policy should not be imposed that increased costs to ratepayers. At worst ratepayers should be no worse off than without QF power (TR 140, 169-170); (2) a need for consistent standards for the treatment of: (i) alternative energy suppliers including utilities; QFs and conservation, (ii) utility revenue requirement purposes, and (iii) rate design (retail); (3) accurate avoided costs to encourage optimal QF development and minimize the misallocation of resources, and (4) dynamic efficiency: the flexibility requirements of balancing supply and demand (TR 161).

68. The MCC set forth the following avoided cost price options:

1. Regional avoided cost;
2. Comparative regional and inter-regional sales and purchases;
3. Long run marginal cost;
4. Total revenue requirement;
5. Competitive bid.

69. Regional avoided cost data sources include BPA's 7(f) rate, and avoided costs that the Northwest Power Planning Council might develop. Long-run marginal cost approaches include the previously discussed base peak, peaker and fuel offset methods.

70. Of these various approaches for computing avoided cost prices, Wilson preferred the peaker approach and the competitive bid concept (Exh. No. 14, pp. 33, 34 and 45-57, and TR 176, 177). Wilson characterized the base-peak approach as an inferior approach on which to base avoided cost prices. This criticism is due to the absence of a resource ceiling or limit on QF resource acquisitions (Exh. No. 14, p. 56, TR 176, 177, and 191 and Data Response JW-20-ii to the Commission Staff). In contrast to the peaker approach, Wilson stated that the revenue requirements approach is not readily verifiable (TR 109).

71. Wilson found the competitive bid concept as a means to reconcile policy concerns, noting no apparent bar to its use (Exh. No. 14, pp. 45-57). The party with the lowest bid would, in effect, establish a price signal that could, in turn, be the basis of avoided cost prices (Exh. No. 14, App. A., P. 4).

72. Wilson testified that the competitive bid approach achieves the following: (1) it insures that avoided cost prices satisfy the PURPA guidelines previously discussed; (2) it precludes wasteful resource development (TR 178), and (3) in the case of MDU and PP&L, may provide cost-effective resource development on a multi-state basis.

73. In terms of whose perspective is relevant in developing avoided cost prices, Wilson was sympathetic to Power's position. In sharp contrast to Power, however, Wilson stated that costs to consumers should not be raised for purposes of developing a QF industry (TR 158). Wilson agreed with Power in that, if this Commission fails to disallow future excess costs, then injecting competition in the short run (assumedly at greater than opportunity costs) is worthwhile (TR 160).

74. The bottom line to the Wilson proposal appears to be consistent treatment of QF and utility resource additions. If a utility is both surplus and attempting to rate base a resource, cost disallowances down to market value are in order (TR 173). The resulting market value would also be the avoided cost price. However, Wilson noted that if a utility resource is rate based at greater than market value, he believes that consistent treatment of QF resources should not follow: QFs

should receive avoided cost payments less than that received by the utility for its rate based resources.

MCC on MDU

75. For MDU, Wilson testified that the utility's AVS III resource is an avoidable resource on which avoided cost prices could be based (TR 130, 131). While Wilson conceded that MDU's AVS II and Big Stone resources are not avoidable, he stated that AVS II costs may serve as a proxy for system avoided costs (TR 134), or as a reasonable basis via the existing base-peak approach (Exh. No. 15, p. 20). But, on the other hand, Wilson did not recommend retention of the base-peak approach (MCC Data Response No. 20-ii to the PSC staff.)

76. Like MDU (TR 331), Wilson stated that it would not be correct to use the MAPP Schedule "B" and "H" capacity costs together in a base-peak calculation (TR 213, but see Exh. No. 15, p. 23). Unlike MDU, however, Wilson claimed that the MAPP power pool rates are an economically inappropriate bases for avoided cost prices (Exh. No. 15, pp. 21, 22).

MCC on MPC

77. For MPC, Wilson did not suggest a specific resource on which to base avoided cost prices (but see Exh. No. 15, p. 7). On the contrary, Wilson made explicit which resources avoided cost prices should not be based: Given the regional power surplus, the Commission's exclusion of Colstrip 3 from MPC's rate base, and the Commission's suggestion that Colstrip 3 may not be a cost effective resource, Wilson suggested that a reexamination of avoided cost methods is necessary (Exh. No. 14, pp. 12, 21, 31).

78. Perhaps most importantly, Wilson stated that if any part of Colstrip 3 is excess plant, the excess plant should have economic precedence over new alternative capacity commitments. He stated that it is obvious that it is wasteful to commit society's scarce resources to more plant if Colstrip 3 is excess: Colstrip 3 is a sunk cost from a "resource allocation efficiency" standpoint. The only exception is if the total costs of new generation are cheaper than Colstrip's variable operating cost alone (Exh. No. 14, App. A., p. 23).

MCC on PP&L

79. For PP&L, Wilson recommended BPA's 7(f) rate as the least desirable basis for PP&L's avoided cost prices (TR 123, 125, 126 and 158). Wilson's concern with BPA's 7(f) rate was simply that the 7(f) rate reflects the allocated average revenue requirement of the 7(f) pool and, as a result, is only a valid "second best" avoided cost proxy. For the short term, Wilson, unlike PP&L, argued for a capacity credit, even though additional QF power does not reduce the utility's construction program (Exh. No. 14, p. 42, and TR 200).

Small Hydro Power Interests

80. Thomas M. Power submitted direct (Exh No. 24) and rebuttal (Exh. No. 25) testimony on behalf of several small hydro power interests, including Montana Renewable Resources, Inc., Montana Small Hydro Association, Greenfield Irrigation District and MITEX, Inc.

81. In terms of policy objectives, Power set forth the following concerns: (1) the Commission's prices should reduce monopsony power; (2) those prices should minimize long-run generation costs; (3) Montana should move away from reliance on, and the environmental impacts of, large thermal plants; (4) the Commission should avoid the rate shock associated with large plants and (5) Montana should develop more reliable less costly service with small dispersed QFs.

82. Power did, with certain qualifications, concede that "ratepayer neutrality" is a relevant policy objective. Power's qualification was that ratepayer neutrality is not judged solely in a short-term sense: the ultimate (long run) intent of PURPA is that ratepayers will be better off and not just neutral (TR 524).

83. In terms of a preferred avoided cost approach, Power stated that the base-peak should be retained. Moreover, according to Power, because coal plants are the marginal plants, the cost of coal plants (Colstrip 3) should be used in the base-peak approach (TR 600, 601 and Exh. No. 24, p. 18). Because short-run cost approaches do not achieve the above policy objectives, they should not be used. In this docket, Power equates short-run cost approaches with "cut-throat" competition.

84. Power, in contrast to Wilson, is opposed to a competitive bid process. While Power argues that a competitive bid is the ultimate objective, it is, according to Power, premature to adopt such a concept today (TR 508, 627); Power stated that a transition plan to a competitive bid solution

should be set in motion (TR 509). Power claimed that the BPA 7(f) rate should be rejected as an avoided cost price basis.

85. Power argued that in addition to an avoided cost price based on the base-peak approach (using coal plant and combustion turbine costs, and escalated to 1985 dollars), certain transmission costs must be included in the price. In the case of MPC, the amount should reflect the Commission's rate base decision in the current retail case (TR 618). In addition to including transmission costs, Power argued that (1) the coal plant's capacity factor should be lowered to 65 percent; (2) overhead and common costs should be reflected in the avoided cost price; and (3) QFs should be paid additional transmission-related costs if it can be demonstrated that the utility will avoid such costs.

86. In terms of load/resource plans, Power stated that the present surplus (for MPC and PP&L) is a short-run phenomenon. Power further characterized the surplus as no accident and possibly a monopsonistic strategy: Since 1977 utilities could have analyzed and incorporated into their resource plans prospective QF power supplies (Exh. No. 24, pp. 7-15).

Superior Energy Inc.

87. Ed Whitelaw provided rebuttal testimony (Exh. No. 16) on behalf of Superior Energy Inc. (hereafter "Superior").

88. Whitelaw set forth a number of policy concerns underlying his proposal to base avoided cost on a utility's most recent plant additions. These concerns were: (1) to ensure of the continued development of a least-cost mix of generating capacity; (2) to encourage the move to free-market competition; (3) focus on small resources to meet future growth; (4) to encourage nonutility developers and (5) to assure meeting the objective of ratepayer neutrality (TR 253).

89. Whitelaw recommended two actions to correct for the monopsony advantages enjoyed by utilities (Exh. No. 16., pp. 12, 14, 18): (1) exclude excess utility capacity from rate base until needed and (2) set avoided cost prices equal to the marginal cost of the last facility built by a utility unless the last resource is "atypical" of the utility's current and anticipated mix of resources (Exh. No. 16, p. 21).

90. While Whitelaw argued that the Commission should look at a utility's last facility to estimate long-run incremental costs (ibid, pp. 20, 21, 22, 24, 26), he dismissed the use of a short-run incremental cost estimate because, in part, it requires the "...Commission to second-guess each utility's resource plan" (Exh. No. 16, pp. 16, 23, 24, 25).

91. Whitelaw stated no preference for any particular analytical approach for computing avoided cost prices, but noted that the base-peak approach seemed warranted. According to Whitelaw, the costs of the last facility are what is crucial in setting avoided cost prices.

92. Whitelaw did state when short-run incremental cost pricing is appropriate:

> Q: Do short-run incremental costs have any role in the determination of avoided costs?
>
> A: Yes. The Commission should base avoided cost rates on short-run incremental costs when the expected availability of power from QFs does not extend until the time when the utility intends to begin initiating steps to secure its own additional resources. That is, short-run costs should apply to short-run contracts between an independent producer and a utility. (Exh. No. 16, p. 25)

93. Regarding the competitive bid concept, Whitelaw, unlike Power, stated that the idea is a "nice step" toward the apparent final objective of greater reliance on competition; however, it is premature to currently get into competitive bidding (TR 264, 265). Whitelaw's arguments for not adopting the CB concept were: (1) the competitive bid relies on a "strong assumption" that "none of the participants enjoy price distorting or cost distorting or market distorting power," and (2) "competition doesn't serve the competitive solution as we like to think of it, unless the conditions of competition are met and they simply are not yet met in Montana." (TR 269, 270).

<u>Rural Energy Development Association</u>

94. Jeff Jordan submitted pre-filed direct testimony on behalf of REDA (Exh. No. 30). Jordan's points include: (1) a utility's resource plan, short-run operating costs and melded rates are all irrelevant in setting avoided cost prices; (2) avoided costs are best measured based on resource costs recently added to the rate base (or to be added in the near future); (3) the base-peak approach should be used.

IV. Commission Decision

A. Policy Overview

95. First, it appears clear to the Commission that in the absence of PURPA, utilities would not have voluntarily acquired any QF capacity at this time. As it stands, to the Commission's knowledge, MPC is the only utility in Montana with any QF power on-line.

96. While one can bicker over the soundness of the avoided cost prices that resulted from the previous two avoided cost dockets, at least in the case of MPC, the 35 year fully levelized avoided cost rate is not substantially different from what MPC estimates to be the levelized annual revenue requirement for Colstrip 3 (Compare MPC's 7 cents/kwh levelized cost in "nominal terms" in Data Response No. 1-MPC-1 to the Commission Staff, with the current 35 year fully levelized avoided cost price of about 6.4 cents/kwh and $98/kw.) While the Commission has no precise knowledge of QF supply curves, it is evident that, in the case of MPC, there is a substantial potential supply of QF power: In 1984, MPC estimated the "possible exposure" to be in excess of 200 MW (TR 417). There is an equally impressive response to the avoided cost prices this Commission set for PP&L. (TR 489)

97. The Commission finds inappropriate some parties' proposals to continue tariffing avoided cost price based on the escalated costs of Colstrip 3 and/or 4. MPC and PP&L presently have adequate generating capacity, and have no plans to add additional baseload coal-fired generation plants in their respective long range plans. To invest the economy's scarce resources, based on the those costs is an unnecessary social investment and, in addition, burdensome to MPC's and PP&L's ratepayers.

98. As the Commission's avoided cost pricing decisions in this docket reflect, the business of optimal resource planning is complex. The existence of a marginal cost does not mean the cost will actually be avoided. There are reliability, maintenance timing, location, dispatchability, and sizing considerations that must be taken into account in designing a least cost resource expansion plan.

99. In this docket, the Commission has decided to revise the current avoided cost pricing mechanism. The Commission hopes the change will inspire the utilities to begin analyzing the economic merits of QF power.

100. The options available to the Commission for setting avoided cost prices are numerous. At one end of the spectrum is the competitive bid option. All but MDU and MPC gave this option favorable mention. One issue regarding this option is whether it would be implemented on a short-term or long-term basis. The short-term would feature a bidding of short-run costs. The long-term would feature a bidding of fully levelized costs. Another issue with this option involves who would participate. On one hand there are many questions without answers, as yet, and on the other hand, there is near agreement in this docket, including this Commission, that the competitive bid is a possible policy solution to any existing impediments to efficient electric generation.

101. The Commission's decision in this docket is to provide two avoided cost pricing options. One is tariffed, and serves as a default option. The second option is simply to allow negotiated prices. As with the competitive bid, there are degrees to which the two options may be applied. The tariffed default option could apply to just QFs, or to QFs and utilities. Under this docket, the tariffed default option will only apply to QFs. Clearly, Wilson, for one would argue for equal treatment of QF and utility resources.

102. The negotiated option is essentially a relaxation of a pure competitive bid. The negotiated option may proceed by a QF initiating discussions with the utilities. The utilities, in turn, will have cost estimates and operating criteria for their planned resources. The utilities should acquire QF resources to the extent that such resources meet the operating criteria at equal to or a lesser cost than the utilities' own resources. The negotiated option could be initiated by the utilities putting out a request for resources. If this negotiated option turns out to be a unrealistic, the default option is available.

B. Montana-Dakota Utilities Co.
Tariffed Short-Term and Long-Term Prices

103. The Commission finds that MDU's proposals should be adopted, as modified. First, the marginal running costs must be computed and adjusted according to the general technical issue discussion on running costs that follows. In contrast to MDU's proposal in this docket, which is to not include any tariffed recognition of line losses, O&M, fuel inventory and working capital, MPC proposed such adjustments in Docket No. 83.1.2. It is unclear to the Commission why such costs are avoidable on one utility's system and not on another's.

104. The Commission finds no reason to limit any tariffed option to QFs less than 100 kw in size. If forecasted running cost data were the price basis, such a difference might be appropriate. Even then, however, new runs could be made to compute running costs, assuming an actual QF's size.

105. While approving of MDU's proposal, the Commission has serious concern for the capacity payments MDU proposes to combine with the system lambda component. The first concern is in using the MAPP Schedule "H" capacity price of $2.00/kw. Given this payment is only available six months per year, the annual value is $12.00/kw. In contrast to this proposal, MDU's 1983 street-light conversion study used the costs of a combustion turbine (CT) as the basis of capacity costs (TR 330). In 1983 dollars, the cost was $68.38/kw, a value roughly 500 percent greater. Moreover, at the time MDU performed the lighting study it could have used the MAPP rates (MDU Data Response No. 3 to the QFs). But, rather than perform the analysis using available MAPP capacity costs, MDU apparently used the costs of a hypothetical combustion turbine's costs.

106. The second concern has to do with MDU's proposed long-term capacity payment. To understand this concern one must refer back to the algebraic equality that equates peaker and baseload cost:

$$FC_B + VC_B = FC_P + VC_P$$

MDU's long-term rate proposal combines positive values for "FC_B" with positive values for "VC_P"; algebraically, this is not possible (unless one of the variables has a negative cost). Conceptually, it is wrong, since one does not combine baseload capital costs and peakload variable costs in arriving at avoided cost prices (MDU Data Response No. UTIL-2 i-xii, and Exh. No. 17 p. 9). The FERC also acknowledged a concern for this problem in its rules and regulations. Rulemakings on Cogeneration and Small Power Production, 45 Fed. Reg. 12216 (1980).

107. Although MDU's long-term rate proposal is conceptually in error, it is noteworthy to point out that the annual value of the MAPP rate is very close in value to MDU's 1983 dollar cost estimate of a combustion turbine ($75.00/kw/yr in 1985 dollars versus $68.38/kw/yr in 1983 dollars). Also, MDU has indicated that, pending a Power plant and Industrial Fuel Use Act exemption, a CT may be built in the later 1980's (TR 324).

108. The Commission has one additional concern with MDU's long-term rate proposal. The concern has to do with levelization of capacity costs. Unlike MPC and PP&L, who would propose to levelize in nominal dollars avoidable capacity costs, MDU makes no such proposal since QF power is not considered dispatchable (MDU Data Response No. ALL-2-C to the Commission Staff). Also, given MDU's long-term MAPP cost basis for capacity payments, there is no apparent long-term forecast beyond four years for this cost (MDU Data Response UTIL-2-ii to the Commission Staff).

109. The consequence of MDU's proposal is that the length of contract has absolutely no bearing on the tariffed capacity payment MDU proposes to pay QFs. While MDU's "dispatch" argument has appeal, MDU has not shown that a QF operating with a long-term contract does not have a higher value to the utility than the converse. The Commission will leave this issue to negotiation.

<u>Occasional Power Tariff</u>

110. For the following reasons the Commission rejects MDU's proposed Occasional Power Tariff: (1) the 600 kwh/month limit of energy purchases is an arbitrary ceiling; (2) there already exists a "net billing" option for QFs; (3) MDU's proposal could double collect customer charges. This reason merits an explanation. Since under Rate 92, MDU is not proposing time-of-day metering, an existing customer could opt for "net billing" using an existing meter. In turn, the same existing customer pays a basic charge to MDU each month (if an additional meter is required for net billing there is merit in a separate metering charge); and (4) although a QF may only produce power occasionally, the power production may be at the time of MDU's peak; yet, MDU proposes no capacity payment as it does with the other tariffs.

<u>Other Issues</u>

111. The metering charges on Rates 93 and 94 are approved. However, QFs must have an option for outright purchase of the meter, or purchase with amortization.

<u>Negotiated Prices</u>

112. The tariffed prices should be in lieu of negotiated prices, except where a QF chooses the tariffed option and wants a levelized capacity payment. If a QF can demonstrate its ability to allow MDU to defer, cancel or size down a prospective resource, then the QF should receive the long-run incremental costs associated with the same resource. Two resources come to mind on which negotiated prices could be based. First, MDU indicated interest in a combustion turbine toward the late 1980s. While the Fuel Use Act may preclude MDU from developing this resource, QFs may face no such prohibition.

113. The second resource is the baseload coal-fired AVS III unit. However, MDU's position (TR 129, 132, 323 and 564-566) is that AVS III is not avoidable until an apparent 113 MW deficit, at the time of the AVS III on-line date, is first satisfied. This idea is perplexing.

114. Regardless of MDU's ordering of the 113 MW deficit vis-a-vis the AVS III unit, one can still assume that the cost to MDU of acquiring an additional 113 MW of resources must be at least as costly as AVS III. Otherwise, MDU should abandon its AVS III plans and vigorously pursue additional power from whatever source MDU plans to fill the additional 113 MW deficit. Also, the

113 MW deficit did not emerge in one lump sum in year 1996, but rather grew from a 1 MW deficit in year 1986 to finally equal this forecast deficit of 113 MWs in 1997.

C. Montana Power Company

115. The range of avoided cost pricing proposals for MPC covers nearly every possible approach. The Commission, however, adopts MPC's avoided cost pricing proposal submitted in both Docket No. 83.1.2 and this docket, but with changes. It is appropriate to first review reasons for rejecting the base-peak approach. Accordingly, a brief review of MPC's Docket No. 83.1.2 proposal is provided.

The Base-Peak Approach

116. At present, MPC's long-term avoided cost prices reflect, in part, the escalated costs of Colstrip 3 and 4. In Docket No. 83.1.2, this proxying idea had some relevance, but was imprecise, given the failure to discount the costs.

117. Given MPC's current resource plan, which does not include coal-fired resources, the Colstrip plant costs, as used in the base-peak approach, should be abandoned. To use historic escalated Colstrip 3 and 4 plant costs totally ignores MPC's current resource plan, as well as resource demand.

118. Clearly, parties in this docket do not concur with the proposal to abandon the base-peak approach. Those that oppose changing the status quo for MPC are principally Power, Jordan and Whitelaw. However, some of these interests qualify their positions. In the case of Whitelaw, the recommendation is to base avoided cost prices on the costs of utility's most recent plant addition, unless "...the last plant is atypical of the utility's current and anticipated mix of resources..." (Exh. No. 16, p. 21, and TR 281, 282). Colstrip 3 and 4 are clearly atypical of resources in MPC's current resource plan (as well as PP&L's). But, even if MPC had a coal resource in the plan, the associated costs should still be discounted.

119. Power also appears to relax his proposal to base avoided cost prices on the last resource's plant costs (TR 498, 524, 531, 538, 595, 602 and 608). But, there is no apparent analytical basis to this proposal: If the supply of QF power satisfies resource need "... that rate would cease

to apply, and a lower rate would apply...". But the question is, how much lower, and based on what costs?

120. This last point indicates that the base-peak approach, as Power proposes it to be used, lacks the flexibility to respond to various load/resource conditions. Power's proposal to simply set "lower rates" is arbitrary. The missing element appears to be cost discounting, an idea opposed by all but one of the QFs Power testified on behalf of.

121. In Docket No. 83.1.2, MPC proposed basing avoided cost prices on a combination of marginal running costs and hydro upgrades. This proposal is adopted, with the following changes, in this docket. Marginal running costs (system lambda) must be adjusted as discussed in the technical issues section of this paper.

122. The capacity-related (for generation) avoided cost basis has several complications. First, should MPC's purchased power costs or hydro upgrade costs be used? MPC has suggested that the costs of the upgrades could be used in a base-peak calculation (TR 403).

123. The second complication involves the proper methodology for the use of hydro upgrade costs to set avoided capacity prices. Two choices exist. One is to use MPC's revenue requirements approach. The other is to simply discount the costs for an upgrade. If costs are discounted, then the question arises as to what costs should be discounted. This issue is set forth in the technical issue section on discounting.

124. For the tariffed rate option, the Commission finds appropriate MPC's deferral approach as proposed in Docket No. 83.1.2. The hydro upgrade costs must be used in the deferral calculation. The Commission finds that the hydro upgrades are a reasonable basis for the calculation of avoided capacity costs, given the uncertainty associated with the "purchased power" resources (TR 400-406).

Negotiated Prices

125. QFs must have an opportunity to negotiate avoided cost prices. At least two reasons exist for this option. First, while adopting MPC's deferral approach for the tariffed rate option, the Commission does not believe the resulting revenue requirement based avoided capacity price is appropriate (see the technical issue discussion on cost discounting). A more simple and verifiable

cost estimate would be to discount hydro upgrade costs back to the present. Furthermore, it is not the revenue requirement, but rather the projected annual actual cost expenditures, that should be discounted.

126. The Commission does not propose tariffing transmission related avoided costs (aside from line losses). However, if any of MPC's transmission investments are avoided, the responsible QFs should be so remunerated.

The Cost Tracking Mechanism

127. The Commission approves of MPC's proposed cost tracking mechanism, but only for avoided cost-related expenses. Such costs may be recovered once per year. MPC should attempt to coordinate such increases with ongoing and expected dockets so as to minimize the numbers of rate changes to customers.

D. Pacific Power and Light

128. The Commission accepts PP&L's proposed short-term and long-term avoided cost prices, but with certain changes. The Commission notes that the base-peak approach, using Colstrip 3 and 4 cost data, is currently an inappropriate avoided cost price basis for PP&L (as it is for MPC).

Tariffed Short-Term Prices

129. Several adjustments must be made to PP&L's short-term rates. First, the running cost component (of the three components) must be adjusted according to the technical issue discussion later in this order. This first adjustment is necessary, given PP&L's failure to reflect any O&M, fuel inventory working capital or line losses in their analyses (TR 66, 76). Once more, the Commission finds interesting how one utility (MPC) can find such costs avoidable, yet another utility (PP&L) does not. Also, as evident from the Company's late filed exhibit (No. 4), PP&L has made no less than two million MWHs of opportunity sales in each of the past five years. The effect of such sales must be reflected in the running cost component of the short-term avoided cost price.

130. PP&L must provide a detailed explanation of how they arrive at the final short-term prices. For example, PP&L's proposed 1986 price is 1.8 cents/kwh. But in contrast, the average

annual short-term opportunity sales price over the past five years has never been less than 1.92 cents/kwh.

131. Further, PP&L indicated the Centralia plant is one resource on which running costs are calculated. But from PP&L's 1983 FERC Form No. 1 (page 403), the associated fuel cost alone is 1.33 cents/kwh. If this 1983 figure is adjusted to 1986 dollars using PP&L's expected 6 percent escalation rate (from PP&L's July 13, 1983, data responses to the Commission Staff's data request in Docket No. 83.1.2), one obtains a 1.6 cents/kwh cost, before any adjustments are made for line losses, O&M, working capital or fuel inventory.

132. Just as with MPC's hydro upgrades, it is appropriate to discount future capacity costs to the present. In turn, PP&L's proposed nominal levelization of such costs is approved. Again however, precisely what costs should be discounted is a concern. From Docket No. 84.7.38, PP&L indicated a $76.37/kw cost of capacity in year 1992 from BPA; PP&L has also indicated that capacity costs are roughly equal to 23 percent of BPA's 7(f) rate. The greater of these two capacity costs, discounted to a present value, must be the basis of a short-term capacity payment if PP&L intends to acquire both.

<u>Tariffed Long-Term Prices</u>

133. There are concerns that the PP&L proposed 7(f) rate may actually understate avoided costs. As with the tariffed short-term option, it is not clear that PP&L's 23 percent split of the 7(f) rate into capacity-related costs provides the most accurate indicator of the highest avoidable capacity cost (TR 41, 83). If a utility has two avoidable resources, with different avoidable costs, then avoided cost prices should reflect, the highest cost resource. Accordingly, whether 23 percent of BPA's 7(f) rate or the earlier cited $76.37/kw figure is the highest cost must be determined. Finally, as with capacity, the long-run avoided energy price must be the greater of running costs and BPA's 7(f) rate. PP&L must reflect this concern in its workpapers and tariffs.

<u>Negotiated Prices</u>

134. Given that PP&L's long-term resource plan features BPA's 7(f) rate as the avoidable resource, and PP&L proposes that the same costs be the avoided cost price basis, the issue of price

negotiation is limited. The two candidates for price negotiation would appear to only include the above cited combustion turbine costs and any avoidable transmission investments.

V. Technical Issues

A. Running Costs (System Lambda)

135. Each utility that includes running costs in an avoided cost calculation must compute system lambda in the following manner and make the following adjustments.

136. The most recent three months of data should be used as the price basis for the next three months e.g., actual running costs for January, February and March should be the basis of avoided cost prices in April, May and June; prices will change, at a minimum, every quarter. The utilities may compute and provide data an a monthly basis if they so choose. The use of actual data will tend to reduce existing forecasting errors. Two examples demonstrate this concern.

137. First, the use of actual data as opposed to forecast data allows for the reflection of all loads, both native and off-system, in the calculation (TR 193). While one utility indicated that estimated off-system sales should be included with marginal running costs (see PP&L Data Response All-1-D to the PSC Commission Staff), another utility's estimates sharply diverge from actual experience (TR 401). The difference, for MPC in this case, is 181 AVG MW versus 115.4 AVG MW (based on five years of actual versus five years of forecast data): nearly a 60 percent difference.

138. Second, in Docket No. 83.9.68, MDU forecasted marginal energy costs in 1985 for winter/summer peak and off-peak periods to equal 6.3 cents/3.1 cents and 4.9 cents/2.2 cents respectively. (TR 340) Two years later, in the present avoided cost docket, the 1985 forecast is 2.3 cents (peak) and 1.8 cents (off-peak): given the magnitude of these forecast errors, the use of historic/actual data would appear to be a major improvement over forecast data.

139. Running costs must be adjusted upward to reflect the following cost refinements: (1) variable O&M; (2) avoided fuel inventory and (3) avoided working capital. It should be noted that MPC proposed to include these items in its Docket No. 83.1.2 avoided cost proposal (Direct Testimony of Tom Lovas, Exhibit TA 1-2A).

140. The adjusted running costs must be further adjusted for transmission line losses. The percent adjustment should equal 8.3 percent per kwh as adopted in the Commission's two previous avoided cost dockets.

141. Finally, in computing running costs, the utilities must assume a one MW decrement. Additionally, MPC and PP&L must provide time-of-day varying energy prices if requested by QFs.

142. Before leaving this technical issue, the Commission is obligated to respond to a proposal by the MCC to model an efficiently planned utility. Specifically, Wilson suggests excluding Colstrip 3 from PROMOD runs used to determine running costs.

143. This suggestion by Wilson appears inconsistent on two counts. First, Colstrip 3 is a sunk resource. Wilson's own testimony recognizes this fact (Exh. No. 14, pp. 49, 50, and App. A. pp. 22-26). Yet, Wilson apparently argues in favor of raising the avoided cost price to reflect an efficiently run utility (TR 211-213 and Exh. No. 14, App. A, p. 22).

144. Secondly, there should be a consistent recommended application of the peaker approach. On one hand, surplus power and resource exclusion from a PROMOD run go hand in hand. What about MDU who admits chronic deficits? Why hasn't Wilson proposed lowering running costs for MDU in either this docket or in Docket No. 83.9.68?

B. Discounting

145. The Commission's January 17, 1985, Procedural Order requested parties to address the issue of cost discounting (issue No. II (c) in the Procedural Order). Those parties responding to this issue, except for Power, agree that costs should be discounted to account for the "time value of money." With Power's proposal to not discount, but rather de-escalate future costs, it is immaterial whether ratepayers need a resource today, 20 years from now or 2000 years from now. (See for example cross-examination of Dr. Power in Docket No. 83.9.67, TR 4941.)

146. The Commission's failure to discount avoided costs in earlier avoided cost dockets was criticized by the Montana Department of Natural Resources and Conservation. The Northwest Power Planning Council indicated in a letter to this Commission, that it also applies cost discounting.

The FERC also recognized the economic soundness of discounting future costs to a present value for purposes of computing avoided cost prices.

147. The Commission finds that, as necessary, avoided costs must be discounted prior to computing prices. For example, if MDU's AVS III costs are the basis of an avoided cost price, the costs must be discounted to the present.

148. Precisely what costs are to be discounted is a concern to this Commission. In turn, this issue raises the dilemma of whose perspective is relevant in developing avoided cost prices. The issue is simply, should the annual actual costs incurred by a utility for a future plant be discounted to the present, or should the summation of annual accounting costs, which would be rate based, be discounted. The two discounted present values are not necessarily equal, as is evident from Table 5 below.

Table 5

Illustrative Cost Discounting Examples[1]

Year (1)	Cash Flow W/AFUDC (2)	N (3)	Discounted Values Of Col. (2) (4)
1985	$ 59	0	$ 59
1986	44	1	39
1987	39	2	31
1988	41	3	29
1989	78	4	50
1990	459	5	260
1991	1,251	6	634
1992	1,798	7	813
1993	8,966	8	3,621
1994	4,718	9	1,701
Discounted Present Value	$6,294[2]		$7,237[3]

[1] Date Source: MPC's Cost of Service/Rate Design Supplemental Workpapers. Fuel Offset Tab, page 10 or 12, Docket No. 83.9.67. Partial data for the Kerr upgrade.

[2] The Figure $6,294 was computed by 1) adding up the annual costs ($17,453), as if they would be rate based in year 1994, and 2) discounting this sum back to 1985 using a 12 percent discount rate (N=9).

[3] The $7,237 figure is the sum of the discounted values of each years cost.

149. To restate the issue, the perspective from which one thinks cost should be minimized, shapes the avoided cost price. The $6,249 figure, reflects the discounted present value of the cost MPC would request to rate base. The $7,237 reflects the discounted present value of the annual costs MPC expects to incur. The former (lesser) value reflects the present value of eventual ratepayer costs--the costs to be ratebased. The latter value reflects the present value of economic costs as they are incurred.

150. To the extent practicable, the Commission finds actual annual economic costs must be discounted. In the case of MDU, the actual annual costs of building AVS III should be discounted. In the case of MPC, the actual annual costs of the hydro upgrades should be discounted (the example in column 4 of Table 4 above). As PP&L's resource plan features purchased power (BPA's 7(f) rate), and this rate is based on a meld of resources, the actual 7(f) rate, or components of, should be discounted, as appropriate.

C. Carrying Charges

151. The Procedural Order inquired into what type of carrying charge is appropriate to annualize costs. At issue was the choice between real and nominal carrying charges. Real carrying charges are net of inflation. With the possible exception of Wilson (Exh. No. 14, App. A, P. 13 and TR 187, 188), parties responding to the procedural order issue recommended real carrying charges. The use of real carrying charges must be continued in this docket. The real carrying charge should reflect the following cost components: 1) insurance, (2) depreciation, (3) weighted cost of capital, (4) property taxes (5) state and federal taxes.

D. Levelized Prices

152. Avoided cost prices are presently levelized in three formats: (1) fully levelized (in nominal terms) (2) partially levelized and (3) fully escalating (effectively a real levelization). The issue of levelization is an issue of risk taking.

153. Most parties responded to this Procedural Order issue, advocating real levelization. Both Power and Jordan seem to favor real levelization (TR 603, 285). PP&L's capacity payments,

however, appear levelized in nominal terms (Exh. No. 7, App. A). MPC claims that nominal levelization assumes a plant is needed each year (Exh. No. 19, p. 7) and such an incentive is inappropriate today (ibid, p. 18). Yet, in Docket No. 83.1.2, MPC proposed to offer nominally levelized capacity payments to QFs.

154. For the tariffed rate option, the Commission finds that the energy component should not be levelized in nominal terms. The capacity portion should, however, be levelized in nominal terms: If capacity is not levelized, there would be no price distinction between contracts of varying lengths. To this end, PP&L's proposal in this docket, and MPC's proposal from Docket No. 83.1.2, to levelize the capacity payment in nominal terms are approved. If and when a QF requests MDU to levelize capacity payments in nominal terms, the Commission expects MDU to do so.

VI. Other Issues

155. Several issues remain to be discussed including: (1) information barriers; (2) an implementation phase for utility compliance (filing of workpapers etc.), and intervenor scrutiny and (3) a prospective rulemaking.

A. Information Barriers

156. The utilities should provide avoided cost pricing information to both consumers and producers. First, with regard to information provided to consumers, the January 17, 1985 Procedural Order [issue No. VI D. (b)], raised the issue of avoided cost prices equaling retail prices. Additionally, parties were invited to propose changes to the Commission's rules (ARM 38.5.1901-1908). Further, no party proposed revisions to ARM 38.5.1905(6) dealing with the "net billing" option.

157. The Commission finds that twice per year each utility must provide to every electric customer information on the "net billing" option. Such information must be included along with the customers' bills. The first such notification should occur with billing beginning January 1, 1986.

158. Each utility must provide each prospective QF its resource plans for generation and transmission investments. In order to negotiate nontariffed avoided cost prices, prospective QFs need

information. One example underscoring the importance of such information relates to the mobility of the Bozeman wood plant -- now the Livingston wood plant -- vis-a-vis the proximity to a MPC incremental transmission investment. If requested, the utility must provide prospective QFs cost breakdowns for incremental resources. Such data must reflect estimated annual costs prior to ratebasing and not ratebase (revenue requirement) costs.

B. Implementation

159. The utilities must provide the underlying cost data and workpapers for their respective avoided cost compliance prices. Such information must be provided for the tariffed and negotiated price options. In addition, all such data must be provided to nonutility intervenors in this docket when provided to the Commission. For the tariffed option, each utility must document the development of actual running costs, and the associated working capital, fuel inventory and O&M adders. Precisely how offsystem sales affected running costs should also be documented. PP&L must precisely document how it melded running costs with the other two marginal energy cost components. MPC must show precisely how it arrives at its avoided capacity costs using the hydro upgrades in the deferral calculation. MDU must contemplate having to offer nominally levelized capacity payments and in turn, file a matrix of levelized capacity prices based on contract length; MPC and PP&L must provide the same.

160. Each utility must compute and provide at a minimum 10 years of forecast annual running cost data reflecting O&M, fuel inventory, working capital, off system sales and line loss adjustments. Such forecast (estimated) costs must be included with the tariffed rate option. It should be made clear in the tariff, however, that the cost estimates are not precisely what QFs will be paid.

161. Regarding the negotiated price option, the Commission requests that each utility provide their best cost estimates for incremental resource additions. For MDU, annual cost data for the tentative combustion turbine, and for AVS III should be filed. For MPC, annual cost data on the hydro upgrades should be filed. In addition, MPC must provide unit cost estimates for its "tentative" purchased power resources. For both utilities the annual actual cost incurrences should be provided.

162. At the time any utility decides upon a resource not in its 1985 resource plan, the same utility must submit the annual actual costs associated with the resource. That is, if MPC reconsiders the Salem plant, the Commission requests notification and associated cost data. Such data should be provided prior to the utility's making a long-term contractual commitment to the resource. The purpose of such data is evident: The economy and the ratepayers deserve an opportunity for possible competitors to supplant the same resource(s) at a cost less than the utility expects to incur.

163. If such data exists, the Commission requests each utility to file any forecast estimates of system lambda that may exist. The Commission seeks the utilities' estimates of minimum and maximum system lambdas for each year in each of the next 35 years.

C. Rulemaking

164. The Commission will institute a rulemaking proceeding subsequent to the tariffing of final prices -- under the pricing methods adopted in this docket. Such a proceeding will address concerns raised by MITEX, PP&L and MDU, as well as streamline data reporting requirements to reflect decisions in this docket and to eliminate certain data filing requirements from previous dockets and rules.

CONCLUSIONS OF LAW

1. Montana-Dakota Utilities Company, Montana Power Company and Pacific Power & Light company are public utilities within the meaning of Montana law, Sections 69-3-101 and 69-3-601(3), MCA.

2. The Commission properly exercises jurisdiction over the rates, terms, and conditions for the purchase of electricity by public utilities from qualified cogenerators and small power producers. Sections 69-3-102, 69-3-103 and 69-3-601 et seq., MCA. Section 210, Pub. L. 97-617, 92 Stat. 3119 (1978).

3. The rates the Commission has directed the utilities to file are just and reasonable to Montana ratepayers as they reflect each utility's avoided energy and capacity costs.

4. The objective of encouraging cogeneration and small power production is promoted by the rates, terms and conditions established by this order.

5. The Commission's ratemaking decisions are exempt from the requirements of Montana's Environmental Policy Act, 75-1-101 et seq., MCA. The Commission interprets 75-1-201, MCA, as an exception that applies to the Commission's ratemaking activities. This proceeding is designed to establish rates, and, thus, is included in the exception.

ORDER

1. MDU, MPC and PP&L shall develop rates which are consistent with the Findings of Fact entered by the Commission in this order.

2. Proposed tariffs and requested cost data must be filed with the Commission within two weeks from the date of issue of this proposed order. All parties will have an additional ten (10) days from the time of receipt of the last utilities' tariffs and cost data to file comments on this order. Any comments the nonutility intervening parties may have on the submitted tariffs and cost data must also be filed within the ten (10) day period.

Done and Dated this 3rd day of September, 1985 by a vote of 4-1.

BY ORDER OF THE MONTANA PUBLIC SERVICE COMMISSION

CLYDE JARVIS, Chairman

HOWARD L. ELLIS, Commissioner

TOM MONAHAN, Commissioner

DANNY OBERG, Commissioner

JOHN B. DRISCOLL, Commissioner
(Voting to Dissent)

ATTEST:

Trenna Scoffield
Secretary

(SEAL)

DISSENTING OPINION

Fortunately, this is not a final order; interested parties will be able to see the practical outcome of the theoretical concepts contained herein, as well as offer remedies for problems that are not anticipated. The best architect can build a house, but the people living in it will tell you if its any good; the same is true for Chefs and soupeaters, or Commissions and utilities/power sellers.

This order has several problems more fundamental than implementation, which cause me to dissent:

1. Energy payments that have no certainty at all until a computation of the previous quarter's system lambda inject unnecessary risk into the power seller's business calculations. If its difficult now to take a project to the bank for financing, it will be virtually impossible under this formula. Unless a secondary industry of "fixed power contract offerors" materializes, it's hard to visualize the banking community lending money for developments if this Commission refuses to guarantee even conservative projections of each utility's running costs. Certainly the best solution to this problem is the development of a secondary market of buyers that will offer a firm price to power developers, in much the same way that wheat millers offer firm prices to farmer.

In the absence of a fundamentally new institution in the market, this Commission should remove some of the uncertainty for power developers and sellers by committing to pay future price levels for energy that reflect system lambdas that are virtually certain. We know, for example, that system lambdas will vary from low to high, but likely will never be zero again. Probability analysis will give us a low forecast for system lambda prices; the Commission could at least offer to cover these prices on a levelized contract basis. This will help the power developer at the bank, and probably result in a lower cost of money to all developments.

2. This Docket was started with a series of factual findings in a conventional power procurement docket (Colstrip #3: Docket 83 9 67; Order 5051c: Findings 142, 143, 144, and 145). Note the relevant language in that order:

FF #142. "The Commission finds the state of the record on the subject of least cost from resources to be incomplete. It has before it the perceptions of several experts regarding the availability and price of long-term transactions and a limited number of actual transactions. Although the balance of the loads and resources discussion will conclude that the output from Colstrip 3 is not needed to serve test year loads, it is likely that some additional resources will be needed in the future. Whether such resources will be provided from conservation, firm purchases, QF purchases, or an MPC investor owned facility is not known at this time. In any event, the price and availability of the firm purchase alternatives will need to be known. It would provide a measure of the value that ratepayers must be charged for the additional resource in order that they be more nearly faced with competitive market place prices. Accordingly, the Commission wishes to have before it at that time, the best and most accurate information available.

FF #143. MPC is therefore directed to assemble a tabulation of all in place or contemplated long-term sales which it is aware of both within the Northwest region and to or from the Northwest region and present them in the next rate case. All pertinent details of the sales should be itemized.

FF #144. The Commission does expect MPC to perform an appropriate life cycle analysis comparing these alternatives when and if rate treatment is sought for additional resources in the future.

FF #145. The Commission finds MPC's third curteria, that of minimizing the present value of the revenue requirement in the long-term, to be universally accepted. The method of achieving this varied between MPC and intervenors, but no explicit present value analysis was presented in evidence, with the exception of that performed by Duffield. He concluded that compared to either a purchase alternative or conservation, Colstrip 3 was more expensive on a present value basis. Both comparisons were rebutted by MPC witnesses. Again, the record is not adequate to establish a resource strategy which will minimize the present value revenue requirement in the long-term. CRUCIAL UNANSWERED QUESTIONS WERE RAISED ON THE FULL RANGE OF RESOURCE, COST AND RELIABILITY ISSUES. THE RECORD IN THIS CASE AND THE COMMISSION’S EXPERIENCE IN TWO COMPREHENSIVE AVOIDED COST INVESTIGATIONS REINFORCES THE COMMISSION’S COMMITMENT TO THIS DIFFICULT BUT CRITICAL TASK. THE COMMISSION INTENDS TO EVALUATE FUTURE RESOURCE ADDITIONS TO THE UTILITY SYSTEM ON A BASIS DIRECTLY COMPARABLE TO THE ALTERNATIVES.

THE COMMISSION EXPECTS THAT THE MOST APPROPRIATE TECHNIQUE IS A COMPREHENSIVE AVOIDED COST PROCEEDING."

It's clear that we had already arrived at the notion of treating all resources equally. The central purpose of this docket was to determine how best to do that. Accordingly, the methodology we arrive at here for awarding price to decentralized power producers, must also be the methodology for awarding price to conservation, conventional purchases, and utility owned resources.

This record further reinforces the conclusions drawn in 5051c: "The price paid for decentralized energy and conservation should be the same as the price paid for conventional energy, and vice versa." There is testimony from several economists supporting this approach in this docket (84 10 64). The same pricing methodology should apply across the board.

In this proposed order, however, this "new" more volatile methodology applies only to the decentralized power developer's price. This clearly discriminates in favor of the conventional resource, since they will continue to enjoy long-term fixed price contracts or long-term levelized ratebase treatment. The small power producer vis a vis his banker looks pretty weak as a competitor to the traditional energy producers with established financing relationships and the luxury of fixed price contracts or ratebase.

If the volatile rolling system lambda based energy price is unacceptable to the conventional energy developer and seller because of uncertainty, then we must heed the plight we will be causing the decentralized producer with this order.

Because the fundamental approach of this order strikes me as more flexible practically and more correct theoretically, my preference is to require that this methodology apply to conventional as well as decentralized resources. We should then do what we can (see dissent point 1) to eliminate unnecessary volatility that increases cost to the ratepayer by making development capital more expensive to arrange.

3. There are other problems with this order that will surface in the period before the final order. Many rule type guidelines have evolved in the previous avoided cost orders. Pending

a comprehensive review of the small power production rules, one has to ask what rules in the previous orders shall the utility and decentralized power producers follow until the comprehensive recodification of the "old rules" is complete. Its best to get these kinds of problems to the surface in the comment period so the final order can address them.

In summary, I think that the market price for energy will ultimately be the avoided cost of a utility's new resources; insuring that procurement of all forms of resources is at no greater than market price will be an important future role of this Commission. The attractiveness of the methodology contained in this order (if it is practical) is that its transitional. When the time comes that the rolling system lambda price contained in the default tariff approach is TOO LOW for the market, the UTILITY will be forced to really negotiate under the negotiated approach. My view is that there will be some negotiations before the time when the market value of energy climbs above the rolling system lambdas (best projections), but these will be centered mainly around the decentralized power producer giving up something of value just to get the fixed contract it so badly needs to make a project happen. The real negotiations will begin to happen when the utility honestly begins to realize that the most cost effective resource is at market price, and market price is above the system lambda based price levels that responsible participants are predicting.

THIS ENTIRE APPROACH HAS NO CHANCE OF WORKING IF WE DO NOT APPLY IT TO ALL NEW RESOURCES. IF IT IS NOT APPLIED TO ALL RESOURCES EQUALLY, THE OBVIOUS DISCRIMINATION IN FAVOR OF THE TRADITIONAL RESOURCES WILL MOST CERTAINLY BE A CAUSE OF ACTION AGAINST THE COMMISSION. IF WE USE THE FINAL ORDER TO DISCRIMINATE IN SUCH A MANNER AGAINST THE DECENTRALIZED POWER PRODUCERS I WILL NOT CONCUR WITH IT.