INTERFACE BETWEEN DEVELOPERS OF SMALL HYDRO PROJECTS AND UTILITIES

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As we enter the 1980's, events are occurring in the energy and economic worlds at a whirlwind pace. Many of the changes taking place are unpredictable. This uncertainty in the environment in which developers of small hydro projects and utilities operate heightens the challenges they face as they mutually strive to expand the role of hydropower in meeting the electric energy needs of New England consumers.

Initially this article will address the general obligations of utilities and the role hydropower can play in meeting those obligations. Next, government statutory and regulatory initiatives to encourage the development of small-scale hydropower will be examined. The last section of the article will present those issues likely to dominate future negotiations between developers and utilities.

I. BACKGROUND

Before addressing the development of small hydro projects, it may be helpful to provide some perspective on how a utility approaches its responsibilities. Each electric utility has a basic public service obligation—to provide an adequate, reliable supply of electricity at the lowest reasonable cost. Trying to meet this responsibility is a complex and challenging matter for today's utility management.

A utility must have the capacity to meet the peak power demands of its customers. Each day and each year there is a moment of peak demand which must be served. In order to meet these demands, the generating capacity must be sufficient and reliable. Otherwise, there is an unacceptably high risk that some customers' demands will not be met. If some demands are not met, the utility

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will have failed to meet its public service obligation.

In addition to maintaining sufficient and reliable capacity to satisfy peak customer demands, a utility must be able to run some of its capacity around the clock to produce electric energy. On this energy production side of the ledger, the prime focus is on the cost and availability of the fuel used by the operating power plants.

Each utility also strives to develop an optimal mix of generation to provide capacity to meet peak demands and to produce energy in the most economic manner. This mix is composed of three types of units, each of which tends to be associated with a certain type of fuel.

Some power plants are designed to operate without interruption twenty-four hours each day for many months. They are referred to as base load generation plants. The capital cost to construct such a plant is high, but the fuel and related costs of operation are relatively low. Nuclear and coal plants are best suited for base load service. Due to the current high cost of oil, oil plants are best used for other types of generation. Many utilities, however, are forced by circumstances to use existing oil-fired generation to meet base load requirements.[1]

At night customer demands for electricity subside. Other types of power plants are designed to operate at full tilt during the day and to be cut way back or taken off the line at night. These plants are referred to as intermediate or cycling plants. Both their capital and operating costs tend to be moderate. Coal and possibly oil plants are well suited for this type of service.

Finally, some power plants are designed to operate only during emergencies or at times of peak customer demand for electricity. These plants, known as peaking units, must be sufficiently flexible to start up and stop rapidly when needed. Their characteristics tend to be the opposite of base load plants. They have relatively low capital cost and high fuel costs. The high fuel cost is tolerated because the units are run infrequently. Diesels, oil plants, and gas

1. In 1978 Congress prohibited construction of new oil fired plants. 42 U.S.C. § 8311 (Supp. III 1979).

turbines are used for this type of service.

A hydroplant may be used for either base, intermediate, or peaking purposes depending on the characteristics of the stream on which it is located. Where river flow is sufficient and water storage capabilities are present, hydroplants are ideal for base load generation. Where these characteristics are lacking, hydroplants are suitable for meeting intermediate and peak demand.

Hydropower as an energy source has various advantages from the standpoint of a utility. First, water is a renewable, domestic resource which displaces foreign oil, an important national objective. Second, hydro is an excellent inflation hedge. The capital costs are fixed before the plant becomes operational. The operating and maintenance costs are negligible compared to thermal plants since hydro fuel (water) has little or no cost. The variable costs are thus an extremely small percentage of the total costs of hydropower.

Unfortunately, the bulk of the potential for economically viable hydro projects in New England has already been exhausted. Although there are still hundreds of small hydro sites that could be developed, only a few would make economic sense at the present time.[2] Few undeveloped sites in New England have steady, substantial minimum river flows and water storage capability so that opportunities for new base load hydro developments are regrettably scarce. Most of the region's potential hydro projects, therefore, will be peaking units although a few may qualify as intermediate units.

Ideally, the small hydro developer and the utility purchasing the power output will collaborate to design the project to meet the utility's projected capacity and energy needs.[3] It is important to utilities to be able to control the output of the plant and use it

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2. NEW ENGLAND RIVER BASINS COMMISSION, NEW ENGLAND HYDRO 6 (June 1980).

3. For example, the New England Electric System companies (NEES) have more than sufficient peaking generation and would benefit from additional base load generation. Therefore, a new hydroplant on a small stream with little or no water storage potential and operating only a few hours a day will not be as valuable to NEES as a project that could be run base load.

when needed to meet customer demands. This ability to control how and when the plant will operate is referred to as dispatchability. If a utility has the right to dispatch a hydro facility, it can store the available water and operate the plant as a substitute for the utility's power plants that are the most inefficient or burn the most expensive fuel. Thus, by dispatching the hydroplant, the utility is able to maximize its value to consumers.[4] Utility control increases the plant's capability to meet peak customer demand or emergency situations. It also contributes to the utility's flexibility in meeting load swings.

II. Recent Government Initiatives to Encourage Small Hydro Development

One reason Congress enacted the Public Utilities Regulatory Policies Act of 1978 (PURPA)[5] was to remove barriers it believed were inhibiting the development of small hydro projects. Potential developers feared subjecting themselves to regulation as utility companies. In addition, Congress believed some utility rate and pricing policies were not sufficiently sensitive to the needs of small power producers.[6] To encourage the development of small power production facilities, Congress included various provisions in PURPA—sections 201, 202 and 210[7]—designed to help developers overcome the barriers that assertedly had existed. The following is a discussion of these statutory provisions and regulations promulgated under them.

Under section 201 not all developers of small power production facilities are entitled to the benefits Congress included in

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4. If a hydro facility lacks water storage capability, then the benefits of dispatchability are not available.

5. 16 U.S.C. §§ 2601-2645 (Supp. III 1979).

6. 45 Fed. Reg. 12,215 (1980). There is some evidence contrary to this belief. Prior to the enactment of PURPA, NEES already had agreements under which it was purchasing energy from small hydro projects having an aggregate capacity of about 15 MW. It also had a commitment to purchase energy from a facility having another 15 MW of capacity.

7. Throughout this article these section numbers refer to Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, §§ 201, 202, 210, 92 Stat. 3134 (1978) (codified in 16 U.S.C. §§ 796, 824i, 823a-3 (Supp. III 1979)).

PURPA. A development must become a "qualifying facility"[8] to entitle its owner to these benefits. Under section 202 developers of qualifying facilities may apply for a FERC order requiring utilities physically to interconnect with them.[9]

The heart of PURPA's provisions encouraging development of small power production facilities is section 210,[10] which requires utilities to purchase electric energy generated by hydro and other small power production facilities meeting the Act's qualification requirements.[11] In addition, FERC is directed to prescribe rules governing the rate or price that utilities must pay developers.[12] The rules must insure that the rate is just and reasonable to the utility's consumers, in the public interest, and nondiscriminatory with respect to developers.[13] Furthermore, the rate may not exceed the utility's "incremental cost of alternative electric energy,"[14] which is defined as the cost to the utility of the electric energy which, but for the purchase from the developer, the utility would generate itself or purchase from another source.[15]

Also under section 210, FERC must wholly or partially exempt qualifying hydro facilities with a capacity of thirty MW or less from the Federal Power Act, the Public Utility Holding Company Act, and state laws and regulations governing rates, finances, and organization of utilities.[16] Section 210 also precludes FERC's rules from authorizing qualifying facilities to make sales directly to ultimate consumers of electricity.[17] Each state utility regulatory body must implement the FERC rules within one year after their adoption.[18] FERC has now adopted regulations under both sections 201

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8. 16 U.S.C. § 796(17)(C) (Supp. III 1979). Congress directed the Federal Energy Regulatory Commission (FERC) to adopt regulations prescribing qualification requirements. *Id.*
9. *Id.* § 824i.
10. *Id.* § 824a-3.
11. *Id.* § 796.
12. *Id.* § 824a-3.
13. *Id.* § 824a-3(b).
14. *Id.*
15. *Id.* § 824a-3(d).
16. *Id.* § 824a-3(e).
17. *Id.* § 824a-3(a).
18. *Id.*

and 210 of PURPA.[19] Before discussing them it is worth digressing momentarily to review procedural aspects of the adoption of the section 210 regulations.

The FERC staff initiated the rulemaking process in June 1979 by publishing a staff paper which discussed in detail the issues raised by section 210. The staff paper correctly anticipated those issues which are of vital importance to interested parties. Regional hearings were held in July, and the public was also given an opportunity to submit written comments on the staff paper. Proposed regulations were then published in October[20] with a lengthy introduction indicating that points made at the regional hearings had been carefully considered. Regional public hearings were held in November and December on the proposed regulations, and opportunity to submit written comments was again provided. Public meetings were held with state utility commissioners, utilities, and other interested parties when a final draft was available in January. The final rules were published on February 25, 1980, with a preamble exceeding 100 pages. The rules evidenced careful consideration of the comments that had been submitted. Despite the complexity of the subject matter, the regulations are concise, well drafted, and reflect thoughtful deliberation of difficult policy issues. In short, FERC followed an exemplary administrative procedure, for which it deserves great credit.

The substance of the regulations, however, is more controversial than the administrative procedure followed. The rules, of course, confirm the congressional mandate in section 210 of PURPA that utilities must purchase electric energy made available by qualifying small hydropower producers.[21] Although section 210 refers only to "energy," FERC concluded that Congress intended to require that utilities also pay capacity credits[22] to qualifying facilities. As a result, under FERC's regulations, utilities must also

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19. 18 C.F.R. § 292 (1980). No regulations under section 202 were required.

20. 44 Fed. Reg. 61,190 (1979).

21. 18 C.F.R. § 292.303(a) (1980).

22. A capacity credit is a component of the price a utility pays a developer to compensate him for enabling the utility to avoid having to build a new generating facility.

purchase capacity made available by such facilities.[23]

The regulations expressly authorize utilities and developers to negotiate rates and other terms and conditions different from those which would otherwise be required by the regulations.[24] This provision should not be overlooked. To obtain many of the rights afforded them under the balance of the regulations, developers would have to apply to state regulatory bodies and go through a potentially arduous proceeding. Thus, it is likely that their first resort will be to negotiate with the local utility to avoid the delay, cost, and uncertainty inherent in the regulatory process.

Section 210 prohibits FERC's rules from requiring utilities to pay hydro developers a rate which exceeds the utility's "incremental cost . . . of alternative electric energy."[25] For new facilities the rules require that utilities pay a rate reflecting their full "avoided [energy and capacity] costs."[26] Rates for new facilities which are below the utility's incremental costs are not authorized.[27] The net result is that although Congress established the utility's incremental cost of energy as a purchase rate ceiling, FERC has subverted this mandate by dictating that the ceiling shall also serve as the floor, and that the cost must also incorporate avoided capacity costs. Predictably, reaction to FERC's converting the ceiling into an inflexible floor has been mixed. Developers of facilities are naturally pleased with the result. Utilities believe that in its zeal to encourage development of alternate energy sources, FERC lost sight of the congressional concern for consumers. Throughout the rulemaking, utilities argued vigorously that the regulations should track the statute and leave room for flexible pricing mechanisms. Such mechanisms would enable the utility's ratepayers to receive some share in the savings represented by the difference between the developer's costs of production and the utility's incremental costs. Absent such a mechanism, the developer may attain windfall profits, especially when the utility's avoided costs are based on

23. 18 C.F.R. § 292.303(a) (1980).
24. *Id.* § 292.301(b)(1).
25. 16 U.S.C. § 824a-3 (Supp. III 1979). See text accompanying notes 14 and 15 *supra*.
26. 18 C.F.R. § 292.101(b)(6) (1980).
27. *Id.* § 292.304(b)(2).

world oil prices. Petroleum prices bear no relationship whatever to the developer's production costs or revenue requirements.[28]

Utilities do not begrudge reasonable profits to developers, but believe that purchase rates equaling their incremental costs will in many cases be unreasonably high. Such high rates, they feel, are unnecessary to encourage development of small power production facilities and are in contravention of the congressional mandate that rates must be "just and reasonable to the electric consumers."[29]

FERC asserts that its approach is appropriate to encourage developers for the following reasons. First, utility customers will pay the same rates as if the utility had not purchased energy and capacity from the qualifying facility. The nation will benefit from decreased reliance on fossil fuels. Also, any rate reductions that would have resulted from a shared savings approach would be insignificant for individual utility customers. Finally, Congress intended to exempt developers from the rigors of traditional utility cost-of-service regulation.[30]

In determining the utility's avoided costs, the regulations require utilities to make available to state regulatory bodies extensive data concerning their estimated future energy and capacity costs.[31] The state commissions are directed to take various factors into account including data submitted by utilities, the ability of the utility to dispatch the plant, the reliability of the plant and the utility's need for capacity.[32] The rules recognize that if construction of a facility commenced prior to the enactment of PURPA, it is not necessary to provide for a purchase rate that encourages its development. Thus, state commissions are expressly permitted to

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28. Water, the "fuel" for a hydroplant, does not ordinarily increase in price over time. Therefore, the developers' costs of producing power are likely to remain relatively constant. Since the utility's incremental costs are rising rapidly, the spread between a developer's costs and the revenues he receives is likely to become enormous after the first several years of operation.

29. 16 U.S.C. § 824a-3(b)(1) (Supp. III 1979).

30. 18 C.F.R. § 292.304a (1980).

31. *Id.* § 292.302.

32. *Id.* § 292.304(e).

establish rates below the utility's avoided costs for existing facilities.[33] Finally, for each utility a standard rate must be put into effect for purchases from facilities having a capacity of 100 kW or less.[34]

A further provision of the section 210 regulations tracks PURPA's provisions exempting qualifying hydro facilities having a capacity not exceeding 30 MW from various types of regulation.[35]

Most hydro facilities will be developed for the sole purpose of selling electric energy to utilities. A few, however, will be designed to meet some or all of the developer's own needs for electricity. In this latter situation, utilities are required to sell any requested energy and capacity to the developer.[36] The regulations track the statute, which requires rates for sales to be just, reasonable, in the public interest and nondiscriminatory.[37] If requested by a developer, the utility must provide supplementary,[38] backup,[39] interruptible[40] and maintenance[41] power.[42] The rates for sales of backup and maintenance power must take into account the extent to which the developer's scheduled outages can be coordinated with the utility's. These rates may not be based on an unsupported assumption that forced outages by all qualifying facilities will occur simultaneously or during the utility's peak period.[43]

Section 202 of PURPA authorizes FERC, upon application of

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33. *Id.* § 292.304(b)(3).

34. *Id.* § 292.304(c)(1).

35. *Id.* §§ 292.601-.602. See text accompanying note 16 *supra*.

36. 18 C.F.R. § 292.303(b) (1980).

37. *Id.* § 292.305(a)(1).

38. "Supplementary power" means energy or capacity supplied by a utility regularly used by a qualifying facility in addition to that which the facility generates itself. *Id.* § 292.101(b)(8).

39. "Back-up power" means energy or capacity supplied by a utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility. *Id.* § 292.101(b)(9).

40. "Interruptible power" means energy or capacity supplied by a utility subject to interruption by the utility under specified conditions. *Id.* § 292.101(b)(11).

41. "Maintenance power" means energy or capacity supplied by a utility during scheduled outages of the facility. *Id.* § 292.101(b)(10).

42. *Id.* § 292.305(b)(1).

43. *Id.* § 292.305(c).

a qualifying hydropower producer, to order utilities to connect their transmission facilities with qualifying hydro facilities.[44] In adopting the regulations, the Commission concluded that a requirement to interconnect with qualifying facilities is subsumed within section 210 of PURPA.[45] In reaching this conclusion, the Commission rejected arguments presented by some utilities that provisions of section 210 and 212 of the Federal Power Act[46] require qualifying facilities to meet certain tests in order to be eligible for interconnection. The FERC regulations require developers to pay the cost of interconnecting and authorize state commissions to allow the developer to reimburse the utility over a reasonable time period.[47]

The states are required to commence implementation of the PURPA program by March 20, 1981.[48] Implementation may take the form of regulations, an undertaking to resolve disputes between developers and utilities, or any other reasonable approach.[49] Several individual utilities and Edison Electric Institute, the electric utility trade association, petitioned FERC to rehear, reconsider, and revise portions of the regulations. FERC rejected the main thrust of these petitions, and appeals have been filed by the utilities.[50]

III. Issues Likely to Dominate Negotiations Between Small Hydro Developers and Utilities

The following issues are likely to arise in discussions between small hydro developers and utilities. In some cases the cost to a developer will be a great deal lower than the utility's avoided or incremental costs, particularly if the cost of imported oil continues to skyrocket. As other businesses, utilities strive to keep their costs as low as reasonably possible. Many utilities can, therefore, be ex-

44. 16 U.S.C. § 824i (Supp. III 1979).
45. 18 C.F.R. § 292.303(c).
46. 16 U.S.C. §§ 824i, k (Supp. III 1979).
47. 18 C.F.R. § 292.306 (1980).
48. *Id.* § 292.401.
49. *Id.*
50. *Id.* §§ 292.303(c), .204(b), .601(b).

pected to seek purchase rates which afford their consumers a chance to share in the resulting savings. Inability to obtain a share in projected savings as a result of FERC's purchase price regulations[51] dampens the incentive for utilities to promote the advent of small power production facilities. In a situation where a developer will capture windfall profits, utility management believes that it should seek a share of the power production cost savings for its customers.[52]

The regulations require a utility to pay capacity credits if the use of the small hydro facility enables the utility to defer adding capacity of its own and if the facility is dispatchable, reliable, and available during daily and seasonal peak periods.[53] Some small hydro developers will probably make strong pleas during negotiations for capacity credits. Many utilities can be expected to resist payment of capacity credits on various grounds.[54]

Section 210 of PURPA prohibited FERC's regulations from providing a rate to developers which exceeds the utility's incremental, or avoided, cost.[55] Nevertheless, the preamble to the FERC regulations expressly allows the states to enact laws or regulations providing for rates exceeding the utility's avoided cost.[56] Utilities may question whether FERC's approach is valid in light of its apparent inconsistency with the congressional intent that avoided costs serve as an upper limit. Although there are hundreds of potential small hydro sites remaining undeveloped in New England,

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51. *Id.* § 292.304 (1980).

52. It must be emphasized that the utility stockholder's profit is not enhanced by the shared savings concept. The stockholder's interests are not affected in any way unless a regulatory body were to conclude that the price paid by the utility to the developer had been overly generous. In such event, any excessive amounts paid to developers may be ruled to have been imprudently spent and therefore recoverable only from stockholders rather than consumers.

53. 18 C.F.R. § 292.304(e) (1980).

54. NEESPLAN is a fifteen year corporate plan designed to reduce the need for additional electric generating capacity. As a result of the comprehensive load management and conservation programs in the plan, New England Electric does not anticipate the need for additional capacity for approximately twenty years. Any capacity credits paid unnecessarily would have the undesirable effect of charging consumers twice.

55. 16 U.S.C. § 824a-3 (Supp. III 1979).

56. 45 Fed. Reg. 12,221 (1980).

most of them are not economically feasible unless a stream of revenues is provided which exceeds the purchasing utility's avoided costs. Given the utility's public service obligation to provide an adequate, reliable supply of electricity at the lowest reasonable cost, there is a clear conflict. If the utility pays more than its avoided cost to enable development of small hydro projects, its obligation to minimize costs is undercut. If the utility resists paying more than its avoided costs, the rate of development will be retarded. From the utility's perspective, the logical solution to this dilemma would be to broaden the already liberal availability of government grants, loans, and tax subsidies. This approach has been used in the past when public policy favored the development of other enterprises.[57]

As noted earlier,[58] a limited number of hydro projects are designed to meet some or all of the developer's own needs for electricity. In these situations, the developer will need to buy electricity from the utility. If the developer's demand exceeds the capacity of his facility, he will require supplementary power. Whenever the hydro facility is not operating, he will need backup service.

In these relatively rare cases, an issue likely to arise is whether the utility's rate can be based on the expectation that the small hydro facility will cease or reduce operation simultaneously with the utility's time of peak demand. If such an expectation is justified, the utility must keep costly reserve capacity available to serve the developer's needs while his hydro facility is not operating. The expense of keeping such reserve available should be reflected in the utility's rate. This approach, however, is likely to make the backup rate prohibitively expensive. Rates may not be based on the assumption that outages by all qualifying facilities on a utility's system will occur during the utility's peak period unless factual data support that assumption.[59] If available data demonstrate, however, that diversity among hydro facilities or among all types of qualify-

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57. For example, oil exploration activities receive favorable tax treatment, such as depletion allowances.

58. See text accompanying note 36 *supra*.

59. 18 C.F.R. § 292.305(c) (1980).

ing facilities on the utility's system is so limited that reserve capacity must be kept available, the utility's rate can properly reflect the cost of doing so.

In some situations a small hydro developer may not ask the local utility to buy the output of the facility. Instead, the developer will request the utility to transmit the power to one or more other locations for consumption by either the developer or other customers of the utility. The act of a utility in transmitting power across its lines as a service for somebody else is known as "wheeling" power. Many utilities can be expected to oppose wheeling, preferring instead to purchase the power output for the benefit of all its customers. No provision of PURPA or the Federal Power Act requires utilities to wheel for small power producers. Indeed, section 210 of PURPA expressly precludes FERC's rules from authorizing qualifying facilities to make sales directly to ultimate consumers of electricity.[60] Research discloses only one state statute in New England purporting to require utilities to wheel power for small power producers. New Hampshire's Limited Electrical Energy Producers Act[61] (LEEPA) authorizes developers to sell power to not more than three purchasers other than the local utility. The local utility is required to wheel this power under terms approved by the New Hampshire Public Utilities Commission. LEEPA is designed to assure the utility fair compensation, unimpaired reliability and adequacy of service.[62] Whether or not the validity of this provision of LEEPA will be challenged remains to be seen.

In states without a statute similar to LEEPA, utilities may refuse to wheel for small power producers if they believe it contrary to the best interests of their customers. If the utility does agree to wheel, establishing the wheeling rate will be a key issue. In addition, the utility may have to provide supplementary power if the small hydro facility does not provide the total requirements of the customer to whom the power is wheeled. Also, whenever the small hydro facility is not operating, backup service from the utility will

60. 16 U.S.C. § 824a-3 (Supp. III 1979).
61. N.H. Rev. Stat. Ann. § 362-A (Supp. 1979).
62. *Id.* § 362-A:2-a.

be needed. Thus, the supplementary and backup service rates will also be critical issues.

As indicated earlier,[63] the FERC regulations conclude that FERC has inherent authority to order utilities to interconnect with qualifying facilities.[64] Many utilities believe FERC's conclusion is erroneous and that section 210 of the Federal Power Act requires administrative proceedings to assure the safety and reliability of the proposed interconnection. This issue may have to be resolved by the courts. Unless and until the courts reverse FERC's interpretation, the interconnection issue is unlikely to be a significant factor in dealings between utilities and developers of small hydro projects.

One important nonlegislative issue which will arise relates to the developer's financing arrangements. Developers seeking financing typically must demonstrate to the prospective financier that they have an assured, adequate stream of revenues for the entire term of the financing. Convincing a utility to sign a long term contract to buy electric energy is an ideal way for a developer to satisfy this need. Yet the utility takes a risk if it signs a long term power purchase agreement that does not provide its customers any share in potential cost savings. This statement may seem unwarranted since the regulations reject the shared savings approach and provide instead that utilities pay their full avoided costs to developers. The FERC regulations, however, do not require utilities to sign long term purchase agreements. Thus, any utility that agrees to pay its avoided costs over a significant time period risks the possibility that incremental fuel oil costs will continue to accelerate at breakneck speed. It is possible that before the agreement terminates FERC would revise its regulations to provide for shared savings precluding unnecessary windfall profits. In such event, a rate regulatory commission prone to Monday morning quarterbacking might adjudge some of the payments by the utility in the later years of the contract to be imprudent.

Current New England Electric policy seeks pricing concessions

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63. See text accompanying notes 44-47 *supra*.
64. 18 C.F.R. § 292.303(c) (1980).

for its customers when feasible in return for long term power purchase agreements with developers. New England Electric has executed agreements with small power producers which demonstrate that a price lower than New England Electric's full avoided costs is sufficient to encourage the development of alternate energy sources.

Conclusion

Successful future development of hydro facilities in New England will require harmonious cooperation among utilities, developers, financiers, and regulatory officials. Without important contributions by each, development will be retarded. Utilities provide a market for the power and a projected stream of revenues needed by developers to obtain financing for their facilities. Hydro developers provide electric energy from a renewable resource thereby reducing our dependence on oil imports. When the economics are sufficiently beneficial, developers can also reduce consumers' utility bills. Financiers will provide developers the funding they require to meet the frequently heavy capital costs associated with hydro projects. State regulatory officials must exercise sound discretion in implementing the federal requirements and mediating disputes that may arise between utilities and developers.

As long as utilities and developers recognize the other's legitimate, basic needs and objectives and strive to achieve compromises that protect those objectives, the decade ahead should see significant progress in the development of small hydro projects in New England.