American and Canadian Responses to the Challenge of Small Power Production

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Introduction

Small power producers\textsuperscript{1} are in the vanguard of the movement towards the increased use of “alternative” modes of generating electricity. Wind, water, solar, biomass, and cogeneration (which creates useful heat and electricity in one process) power sources promise increased efficiency, reduced environmental impacts and increased energy self-sufficiency.

This paper undertakes to examine the interactions between small power producers and the established utility sector in North America. In particular, it examines the economic and institutional barriers faced by small producers attempting to gain access to utility-controlled electricity markets.

In the United States, significant movement towards overcoming these barriers began in 1978 with the passage of the Public Utility Regulatory Policies Act (PURPA)\textsuperscript{2} aimed at, \textit{inter alia}, encouraging the growth of small power production. As a result, the United States has become the world leader in small power. Canada, lacking any similar initiative, has been left far behind.

The thesis of this paper is that the American experience with small power production provides a useful model for legislators and policy-makers working towards developing a viable small power production sector in Canada. In the first part of the paper I will provide an “electric primer” for readers unfamiliar with basic electrical concepts, generation technologies and the workings of the electricity industry in North America. In Part II, I will outline the problems currently faced by the established utility sector and the benefits which may accrue to society by turning to small power production. The third part of the paper will set out the institutional and economic obstacles faced by both American and Canadian small producers. An analysis of the American response to the

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\textsuperscript{1} Relatively small-scale, privately-owned, decentralized electricity generation facilities not owned by established regulated public or private utilities. Synonyms include non-utility generators (NUGs), independent power producers (IPPs) and “parallel generators”.

challenge of small power production comprises the paper’s fifth part. Finally, I will survey the Canadian experience in this field with particular reference to Alberta and Nova Scotia. The “lessons” derived from the American experience with small power will be used as a basis for comparative evaluation and for suggesting legislative and policy reforms which may assist in overcoming entrenched impediments to small power production in Canada.

I. An Electric Primer

1. Basic Concepts of Electricity and Electrical Technology

Electricity is a “fundamental form of energy or capacity for doing work”. Commercial electricity may be thought of as a stream of electrons flowing through a wire. “Voltage” refers to the magnitude of that flow; the higher the voltage, the greater the flow of electricity. Electricity is transmitted over long distances at high voltage and then mechanically “transformed” into low voltage electricity suitable for distribution to individual consumers.

The generation of electricity is basically simple. Fuel (traditionally oil, coal or natural gas) is burned in a boiler to produce steam, which turns a turbine. The turning turbine shaft provides mechanical energy which, combined with a device called a generator, produces electrical energy. Electrical output is measured in watts, hundreds of watts (“kilowatts” or kw) or thousands of kilowatts (“megawatts” or mw). The maximum electrical output from a generating plant is called its “capacity rating”. For instance, the capacity rating of a smaller-sized coal-fired plant might be 165 mw; that of a CANDU nuclear plant 640-680 mw; that of a small wind turbine generator 50 kw. Electrical consumption is measured in terms of kilowatt-hours (kwh), which refers to a kilowatt used for an hour. An average household in the United States uses about 700 kwh monthly.

Since electricity cannot be stored (except in batteries) it must be constantly available to users. The minimum level of demand placed upon an electrical system by users is called “base load”, while the maximum level of demand is called “peak load”. Accordingly, the generating capacity used by a utility to satisfy base load is called “base capacity” while that used for peak load is called “peak capacity”. Utilities must be able to satisfy base load requirements while maintaining sufficient reserve capacity to meet peak load requirements. Complex calculations

4. Ibid.
5. Ibid.
are required to match the supply of and demand for electricity not only to accommodate daily and seasonal variations in demand, but also to estimate the future needs of the system. 6

2. Small Power Production Technology

Small power production typically employs one of several renewable forms of energy: solar, small hydroelectric, wind, biomass or geothermal. Another small-scale energy source is cogeneration, which may utilize renewable or fossil fuels. A brief description of each technology will set the stage for further discussion. 7

There are two main types of solar electric technology. Photovoltaic cells produce electricity directly when photons (light particles) are absorbed by a solar cell made of semiconducting materials. The second type of solar technology is called "solar thermal". Solar thermal systems employ a large reflective surface to heat a fluid then used to create steam to drive a turbine. Solar energy is the "ultimate" energy source; low cost (potentially), abundant, and non-polluting. 8 However, photo-voltaic and solar thermal technology is not yet sufficiently advanced to be able to generate electricity on a large scale at a cost competitive to other modes of energy production.

Hydroelectricity is generated by flowing water turning a turbine-generator. This technology is well-established, efficient, and reliable. Of course, hydroelectric facilities need not be small. Environmental consequences (aside from large projects and effects of water accumulation upstream of dams) are minimal. Power generated from such facilities ranges from 50 kw and up. 9

Wind-power systems utilize vertical or horizontal-axis wind-turbines to generate electricity. These latter-day "windmills" are grouped in wind-farms located in mountain passes, coastal plains, and other windy

6. Ibid., at pp. 445-46.
areas. Individual turbines generally produce between 50 kw and 500 kw of electricity.10

Biomass electrical generation involves burning naturally-occurring materials (e.g., wood "wastes" from sawmills) to produce steam used to generate electricity.11 These facilities may range up to 100 mw capacity, but are only economical when low-cost biomass fuel is readily available.12 Negative aspects of biomass power include potential deforestation and smokestack emissions.

Geothermal plants use thermal energy from the earth’s core to generate electricity. This form of energy is well-suited for facilities of 20-50 mw.13 Cogeneration is "the simultaneous production of electric power and useful thermal energy in one technological process". Typically, such facilities burn renewable or fossil fuel to produce steam for an "on-site" industrial application (usually for large industries requiring a great deal of heat for production purposes such as chemical plants, pulp and paper mills, oil refineries, smelters, and foundries). The steam is then also used to generate electricity to meet the needs of the facility. Any excess electricity generated is sold to a utility.14 The amount of electricity produced by a cogeneration facility depends mainly upon the size of the particular industrial establishment to which it is attached, but tends to range between 10-300 mw.15 Cogeneration of heat and power by industry dates back to the last century.16

3. The Nature and Functions of Electric Utilities

Before we consider any further aspects of small power production, it is necessary to have a basic understanding of the institutional, legal, and economic context of electricity generation in North America. Comparative analysis (between territorial jurisdictions and between specific utilities) is relatively straightforward because the industry as a whole is structured around the same basic set of principles.

11. Huss et al., supra, note 9.
12. C.J. Weinberg and R.H. Williams, supra, note 7, at p. 151.
Generally, "public utilities" are publicly or privately owned business organizations engaged in the provision of water, gas, telegraph and telephone services, electricity and street transport.17 Utilities are considered "public" because they are legally deemed to be "affected with a public interest"18

Utilities possess several key characteristics. First, they provide "essential" services for which consumer demand is less flexible (or elastic) than for many other goods or services.19 Second, they provide services which can neither be stored nor deferred. Third, they require large initial outlays of capital to build facilities and purchase equipment. These outlays must be recouped over a period of time.20

For my purpose, however, I will focus upon two further defining characteristics. Public utilities are usually monopolies. "Monopoly" in this context means that a utility is the holder of an exclusive franchise to provide a stipulated service over a defined service area.21 Another important characteristic is that public utility monopolies are conferred by governments. Thus, for example, in Nova Scotia the Power Corporation Act22 confers authority upon the Nova Scotia Power Corporation (the provincial electric utility) to

"regulate and control the generation, transformation, transmission, distribution, supply and use of power in the province..."23

Essentially, governments grant utilities monopolies in exchange for broad powers of regulatory oversight, including the authority to regulate prices.24 Utilities receive the right to occupy a non-competitive marketplace and to realize a "just and reasonable" rate of return on their investment. Moreover, utilities are legally obliged to provide universal service at reasonable prices.25

Government, for its part, receives the assurance that electrical energy will be supplied to all who require it. It may also intervene to insure that

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18. Ibid.
19. That is, "the quantity purchased is normally not significantly affected by small price changes". Ibid.
20. Ibid., at pp. 18-21.
22. R.S.N.S. 1989, c. 351.
23. Ibid., at s. 33(1).
24. Farris and Sampson, note 17, at p. 22.
25. Ibid., at p. 21.
a high quality of service is provided at a reasonable cost to rate-payers.\(^{26}\) Each of these objectives are aspects of government's overriding duty to foster economic growth.

There is considerable overlap between the interests of government and those of utilities. Economic growth is an imperative of government and of any corporate entity within free-market economies. For example, section 6 of Nova Scotia's *Power Corporation Act*\(^ {27}\) sets out the raison d'\'etre of the Nova Scotia Power Corporation: "to develop for Nova Scotia the maximum use of power on an economic and efficient basis".\(^ {28}\) Governments delegate utility oversight functions to administrative bodies usually called "Public Utilities Commissions" or some variant thereof. These bodies exercise no small power in view of the rather "open-textured" (that is, indeterminate or open to various interpretations) standards (such as "public convenience and necessity") they are called upon to interpret in discharging their statutory duties.\(^ {29}\) There may be considerable movement of Commission personnel between more openly "political" jobs in government and jobs with regulatory commissions.\(^ {30}\)

Finally, the rate-payer or customer is entitled to be charged a "just and reasonable" price for electricity.\(^ {31}\) Also, rate-payers are entitled to receive service free of undue discrimination.\(^ {32}\)

4. *Note on Private vs. Public Utilities*

Does the presence/absence of the profit motive in some way affect or determine the behaviour of a utility? The answer is "yes". For while the privately-owned utilities *must* turn a profit in order to remain in existence

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26. For example, regulatory authorities are empowered to compel the utility to use certain financial and accounting practices, expand service to new areas, continue operating certain unprofitable aspects of its business, prohibit discrimination against customers for services, and so on. *Ibid.*, at pp. 69-71.
27. R.S.N.S. 1989, c. 351.
30. Farris and Sampson, *supra*, note 20, at pp. 64-65.
31. A "just and reasonable" rate of return realized by utilities is virtually equivalent to a "just and reasonable" rate paid by consumers. This is because an unfairly high rate of return, by definition, means that rates are unreasonably high. *Ibid.*, at p. 79.
32. "Discrimination" may be defined as treating similar customers significantly differently, or as treating significantly differing customers similarly. *Ibid.*, at p. 70.
publicly-owned utilities can operate indefinitely on a break-even basis, or even at a loss, so long as the public purse is available to subsidize and/or underwrite its operations.\textsuperscript{33}

Later in this paper I will argue that small power producers have proven to be more economically competitive with large utilities in the United States than in Canada in part because American utilities, unlike their Canadian cousins, are forced to charge rates which more accurately reflect the "real" cost of producing electricity. This is because they must function as self-sustaining businesses with less support from governments. Public utilities may also be susceptible to a larger degree of "political" influence than private utilities by virtue of government's power of appointment and by specific provisions of enabling statutes which incorporate governmental policy objectives.\textsuperscript{34}

II. The Crisis of "Big Power"

That the electricity industry in North America is of a monopolistic character is indisputable. But why should any utility receive a monopoly in electricity production? The very idea of monopoly is anathema to market-based economics.

In fact, there was a "free market" in electricity which obtained from the later nineteenth century to the early twentieth century. In those days freebooting entrepreneurs would approach town and city councils with proposals to establish what are now considered to be essential services (water, gas, electricity). The results were often unsatisfactory. Abusive pricing practices, slipshod service, mechanical failures, and utility collapses (due to under-capitalization) were common.\textsuperscript{35}

It also became increasingly clear that competition among private electric utilities made no economic sense. Competition led to the unnecessary duplication of electricity transmission and distribution lines.\textsuperscript{36}

\textsuperscript{33} E.g., Nova Scotia Power Corp. pays no taxes; it may borrow money and issue bonds on the credit of the Province of Nova Scotia. See Power Corporation Act R.S.N.S. 1989, c. 351, ss. 8(3), 16. Many public utilities in Canada have in fact operated at a loss through much of the 1980s including the Nova Scotia Power Corporation. See infra, p. 555.

\textsuperscript{34} Farris and Sampson, supra, note 17, at pp. 282-83. See also Public Utilities Act, R.S.N.S. 1989, c. 380, s. 48, which directs the N.S. Power Corp. to "maximize the use of indigenous resources". Regional development (the support of faltering Cape Breton Coal producers) objectives thus supplement the goal of providing power on an "economic and efficient basis".


\textsuperscript{36} Tomain, et al, supra, note 3, at p. 470.
Economies of scale could be realized by building ever-larger generating facilities.\textsuperscript{37}

Government acceptance of the theory of "natural monopoly" eventually led to the demise of utility competition and the instantiation of public utilities as regulated monopolies.\textsuperscript{38}

The 1945-73 period was "Big Power's" heyday. For example, the largest coal-fired plants in 1955 were about 300 mw. By the early 1970s, 1,300 mw capacity ratings were common.\textsuperscript{39}

The bubble burst in 1973 when oil prices doubled almost overnight. Electricity rates began to climb,\textsuperscript{40} leading to a sudden, unforeseen drop in demand.\textsuperscript{41} Many of the large, expensive facilities under construction at that time had been undertaken with the expectation that the demand they were intended to satisfy would materialize just prior to their completion. As a result, utilities were often faced with new capacity coming "onstream" at a time of constant or decreasing consumer demand. Since public utility commissions generally refused to increase rates with the frequency requested by the utilities, many were forced to borrow money from capital markets at high interest rates.\textsuperscript{42} Difficulties with spiralling costs were only compounded by increasingly stringent safety and pollution control requirements, as well as pressures from environmentalists and anti-nuclear activists. In short, it was no longer apparent that bigger automatically meant better.

1. \textit{Economic Advantages of Small Power Production}

The high cost of producing electricity in the 1970s coupled with uncertain consumer demand significantly changed the outlook for small power producers. The achievement of greater economies of scale was hindered by rising fuel prices.\textsuperscript{43} Suddenly the emphasis on producing more shifted to producing more efficiently.

\textsuperscript{37} \textit{I.e.,} the cost of producing a unit of electricity falls with each additional unit produced. "Because electricity production is so capital intensive [not labour intensive], economies of scale dominate an electric utility because costs decrease as sales increase." \textit{See} J. Fuller "Cogeneration and Small Power Production: Florida's Approach to Decentralized Generation", (1984), 9 Nova L.J. 25, at p. 27.

\textsuperscript{38} The rationale for eliminating competition, from a governmental viewpoint, was that "one enterprise's fixed costs can be spread across more sales than if two firms must split the market demand. Thus, the idea of a government imposed monopoly of power production and distribution was well-founded and in the ratepayer's best interest." \textit{Ibid.,} at p. 28.


\textsuperscript{40} Between 1973-1979 prices nearly doubled. \textit{Ibid.,} at p. 300, n. 29.

\textsuperscript{41} From 7\% to 2.5\% annually by 1973-74. \textit{Ibid.,} at n. 31.

\textsuperscript{42} \textit{Ibid.,} at p. 300.

\textsuperscript{43} A.E. Reinsch and E.F. Battle, \textit{supra} note 14, at p. 11.
Conventional utility power systems (for instance an oil-fired steam plant) are relatively inefficient, utilizing only 35% of the heat energy released by burning fuel.\textsuperscript{44} Cogeneration systems, on the other hand, boast an efficiency rating of up to 85%\textsuperscript{45}.

Electricity transmission and distribution networks or “grids” are not perfect conductors of electricity. A certain percentage (usually about 5%) of electricity carried from generation to end use is lost due to such “bleeding”. The longer the distance travelled, the greater the loss. Centralized power generation maximizes transmission losses by spreading each generating station’s “customer load” over a wide geographical area. Such losses are minimized when the generation station and the customer are in relatively close proximity. By building smaller, decentralized generation plants in greater numbers throughout a utility service area, greater efficiency is achieved.\textsuperscript{46}

Capital costs of small power plants are lower than those of expensive “megaprojects”, reducing risks borne by rate-payers ultimately responsible for financing such projects. Cost overruns in large-plant construction have become the rule rather than the exception.\textsuperscript{47}

Small power projects can be built relatively quickly (often within one or two years), making such projects more responsive to actual demand for electricity. As it is, “megaprojects” require long “lead times” to be able to be built in time to meet anticipated demand.\textsuperscript{48} As industry analyst Jeff Passmore observes “Since several hundred megawatts of consumer demand cannot be turned on overnight, these new “lumps” of electricity create, and indeed tend to institutionalize, considerable excess system

\textsuperscript{44} Conventional plants generate steam in a boiler which is then passed through a turbine to generate electricity. The steam is then exhausted to a condenser for cooling. Up to 50% of the burned fuel’s heat energy is lost through cooling; 15% is lost through the smokestack as flue gases. Total energy loss: 65%. \textit{Ibid.}, at pp. 9-11.

\textsuperscript{45} Cogeneration systems get “more bang for the buck” by taking advantage of the principle that less fuel is required to produce useful heat and electricity together than to produce them separately. By using steam not only to generate electricity but also as a source of “process heat” its efficiency rating may achieve 85%. \textit{Ibid.}


\textsuperscript{47} For example, Ontario Hydro’s Darlington nuclear plant was initially priced at $4.07 billion. By December 1981 the cost had risen to $6.25 bil.; by Feb 1982 it was $8.2 bil., and by 1984 between $11 and $12 billion. In short, “An epidemic of cost overruns...seems to plague [Ontario] Hydro.” L. Solomon, \textit{Power: At What Cost?}. (Toronto: Energy Probe Research Foundation, 1984), at p. 71. Such overruns are due to many factors: the inherent inefficiency of large bureaucratic structures, the length of time it takes to build such stations (often 10+ years) and the increasing sophistication of the technologies involved; see \textit{ibid.}

\textsuperscript{48} A nuclear plant the size of Ontario Hydro’s Darlington plant takes 13-14 years to build. J. Passmore, \textit{supra}, note 46, at p. 19.
capacity." As a result, rate-payers may be saddled with enormous "upfront" capital costs to meet load demand which may not materialize on time.

Small power producers are able to build and operate generating facilities at a lower cost than large utilities. The huge scale of an established utility's operations (which allows it to undertake "mega" projects) ensure high "overhead" costs for office staff and skilled labour.

Finally, the cost of producing "alternative" energy has steadily declined over the past decade. The cost of solar thermal power has fallen 66%, wind power 75%, and photovoltaic electricity 90%.

a) Environmental Concerns

It is generally acknowledged that, on the whole, small power production is environmentally more benign than the conventional status quo. The dangers of acid rain, carbon dioxide, nuclear waste, and large hydro projects may be substantially reduced by small power technologies.

This is not to say that there are no adverse environmental effects attached to small power production, however. The land area required to support an exclusively renewable-based energy economy would be considerable (tree farms, wind farms, and so on). The ecological disruptions caused by damming every small river and stream would be intolerable to many. Whirring wind turbine noise might be objectionable to some. Nevertheless, small power production still poses fewer environmental risks than conventional modes of generation.

49. Ibid, at p. 18.
50. For example, a Nova Scotian producer was able to build a small hydro facility for much less than the amount Nova Scotia Power Corporation had estimated as the lowest possible cost. Nova Scotia Power's estimate: $950,000 (which it deemed prohibitive): small producer's costs: $250,000. J. Passmore, supra., note 46, at p. 8.
b) **Policy Reasons for Favouring Small Power Production**

Small power production can potentially provide increased local, stable employment. The relatively simple, modular nature of the technology is amenable to localized design, engineering and maintenance skills.\(^{57}\)

Small power production also holds the potential of introducing competitive market forces into presently ossified monopolistic structures of electricity production in Canada. Lower prices to rate-payers will ultimately result. My discussion of the American experience with limited deregulation in the electrical energy sector will amplify this point.

Economists have also recognized that there is no compelling need for any utility to hold a monopoly over electricity *generation*, as opposed to transmission and distribution.\(^{58}\) Utilities have always "hooked up" many different facilities to power "grids". There is no reason why independent producers should not have the power from their facilities also channelled into the network, provided that the utility is willing to transmit and distribute their electricity.

The diverse fuels available for use by small power producers will help to reduce overall dependency upon any single source of energy.\(^{59}\) In geopolitical terms, decreased dependency on foreign energy sources increases domestic political independence.

Additionally, the decentralization of electrical generation may be seen as one aspect of a generalized popular movement towards self-(and community-based) reliance and self-sufficiency. In plain words: "[D]ecentralization will create smaller, more human entities, devoted to efficiency and effectiveness, but with greater commitment to process and human values."\(^{60}\)

Finally, opening the door to small power production represents a key step in the necessary and inevitable transition of western societies to sustainable, non-fossil-fuel based economies. The principles by which

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such an energy future might be structured are commonly referred to as a "soft energy path" or SEP.\textsuperscript{61} Further consideration of the "SEP paradigm" is beyond the scope of this paper.

At this point the reader may think, “If small power production is so great then why do we not have more of it right now?” While small power production presently plays a minor role on the Canadian energy stage, fundamental and far-reaching change has already begun in the United States. But before we can fully understand why small producers have been successful in the United States, we must recognize the obstacles small producers have faced in attempting to gain entry into both countries' electricity industries.

III. \textit{Institutional and Economic Impediments to Small Power Production}

1. \textit{Institutional Resistance}

Utilities generally oppose small power. They sense that small producers pose a threat to the comfortable status quo. If small producers can generate electricity at a lower cost than the utility, or persuade regulators that small power is a socially more desirable form of electricity generation, then utilities face the prospects of lost revenue, customers, and governmental support. The following text will contain several concrete illustrations of utility resistance to the advance of small producers. Canadian utilities have tended to be less overt than their American counterparts in the expression of this resistance.

Regulators have tended to side with utilities. The prevalent attitude is, “If it isn’t broken then why fix it?” Small power is perceived as a threat to the reliability of the system and rate stability.

\textsuperscript{61} These principles are: 1) an emphasis on renewable sources of energy; 2) an encouragement of diversity in energy resources; 3) that energy sources must be matched in scale to specific end-uses (i.e., decentralization of energy production); 4) matching energy quality to end-use need (e.g., most dwellings need heat of less than 100°F.; solar heating provides such heat easily and cheaply and should therefore be encouraged); 5) advocacy of "people-friendliness" in technology—simplicity, understand-ability and safety. R. Paehlke, \textit{supra}, note 55, at pp. 79-82, and ch. 4 generally. Several articles and books have applied SEP concepts to the Canadian context: e.g., R. Bott \textit{et al.}, \textit{Life After Oil} (Edmonton: Hurtig, 1983); D.B. Brooks, \textit{Zero Energy Growth for Canada} (Toronto: McClelland, 1981); R. Paehlke, “Environmental and Social Impacts of a Soft Energy Path” Alternatives 12 (Fall 1984): 21-24; T. Schrecker, \textit{The Conserver Society Revisited} (Ottawa: Science Council of Canada, 1983); R. Torrie \textit{et al.}, \textit{2125: Soft Energy Futures for Canada - 1988 Update} (Canadian Environmental Network, 1988).
2. Economic Impediments to Small Power Production

a) Monopsony Power

In economic terms, a “monopsony” exists when there is a single buyer for multiple sellers. A monopsonist will take advantage of this imbalanced relationship to gain for itself the most favourable terms in any exchange or contract between buyer and seller.\(^6\)

Monopsonist utilities can use their vast pools of resources and expertise to advantage against cash-and-information strapped small producers. For example, utilities have much easier access to expert information than small producers. It costs a small producer comparatively more money to obtain that same information. In the context of a contract negotiation, such imbalances add greatly to a small producer’s “start up” costs.\(^6\)

b) Price

This is the crucial issue. When more “overt” forms of resistance (such as refusing to connect the producer into the electricity grid) are no longer practicable, utilities may still attempt to undercut the viability of small power producers by paying them too little for the electricity they generate. In this section I will set out some of the key issues.

The concept of “avoided costs” has become the focus of much debate in recent years. The general questions in this area are posed in the following terms: “What sorts of costs, usually borne by the utility, are avoided by the use of non-utility generation facilities?”, and “by what standard should these costs be evaluated?”

Discussion has centered upon two key components of utility costs. The first component is “fuel” cost. This type of cost varies according to the amount of fuel consumed by generating plants. The more a generating plant operates, the more fuel is consumed, and the greater the fuel cost (other things being equal). The second component is “capacity” cost. This refers to the cost of additional utility-built generating capacity. Capacity costs, once incurred, do not vary with consumer demand for electricity.

Public utilities agree that small producers’ power, by eliminating the need to operate certain plants, does reduce their fuel costs. The savings thus realized may be credited to the small producer. However, utilities often object to paying small producers any portion of avoided capacity costs because small producers do not generally eliminate a very significant portion of these costs, even though small producers themselves incur capacity costs.

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63. Ibid.
Small producers respond to this argument by contending that they ought to receive an opportunity to be able to replace a greater portion of utility generating capacity. They also contend that the contribution of small producers to utility capacity should be measured in terms of the aggregate effect of their production upon the electrical system as a whole. Seen in this light, it becomes evident that small producers can contribute sufficient power to a system to justify receipt of payment for avoiding utility capacity and fuel costs.

Another problem relates to excess generating capacity. Since utilities must add new generating capacity ahead of anticipated demand, there are often periods during which the per-unit cost of electricity goes down. At these times, therefore, small producers receive a low price for their power. Small producers argue, however, that utilities should act to prevent excess capacity from arising in the first place. It is in no one's interest to create excess capacity in the system. The “sale” prices that follow upon such episodes do not accurately reflect the cost of adding the new generating capacity which gave rise to the excess in the first place. These prices create an effective disincentive to the use of more efficient modes of generating electricity. Consumers may be faced with a steep rate increase when the excess disappears. Small power reduces excess capacity because it is more demand-responsive; that is, facilities can be built quickly to meet actual demand as it arises.

Then there is the question whether utilities should pay small producers at rates equivalent to those paid for expensive “peak capacity” or less expensive “baseload capacity”. Any utility, at a given moment, will have both relatively expensive and inexpensive generating plants available to provide power when needed. More economical plants are operated in order to satisfy baseload demand. More expensive plants will be used during intermittent periods of high demand. Should small producers be paid at rates equivalent to those paid for peaking capacity or base capacity? Or a mixture of both? In Nova Scotia, small producers are paid at rates which reflect the costs of operating a baseload, coal-fired facility. It is at least arguable that small producers should receive payment which reflects some portion of peak capacity whose use is deferred by having resort to the small producer's facility.

c) Production Costs

Finally, there are issues of "externalities". An externality is a "production cost or benefit which is not reflected in the price of a product". The classic example is that of pollution. Pollution imposes costs on society which must be absorbed by someone. If society must pay these costs then the price of the product created by the pollution-causing process does not accurately reflect its true cost of production. Small producers advocate an increased level of "internalization" of currently-externalized costs by all power producers including utilities. Small facilities generate little pollution. As a result, internalising their pollution costs would produce little change in their costs. On the other hand, internalising those incurred by heavily-polluting facilities of the type commonly used by utilities would cause utility costs to rise considerably. Small power would thus become more cost-competitive with large utilities and society would realize a net reduction of costs it currently bears. The same analysis can be employed to provide some accounting for several other net benefits produced by small power such as diversifying the fuel mix, increased employment and so on.

The externalities issue remains unresolved. Pollution-related costs are at the moment not generally borne by electric utilities beyond those costs incurred in satisfying existing legislated pollution-control standards. The key outstanding question here is whether regulatory boards can compel utilities to pay additional avoided costs to small producers for avoiding pollution-control (and other social) costs. No jurisdiction has done so - but see my discussion of avoided costs in the United States in part IV below.

3. Specific Utility Concerns about Small Power Production

In 1986 the Canadian Energy Research Institute asked major Canadian utilities to specify their concerns about the possible negative effects of an increased reliance upon cogeneration by industry. Their responses accord with the general pre-dispositions of utilities towards small producers discussed in the previous section.

The biggest fear amongst utilities was that the reliability of the total electrical system would be endangered by introducing small power production technologies. Respondents considered small technologies

65. Tomain et al, supra, note 3, at p. 36.
67. The concerns listed below are extracted from the discussion at pp. 95-97, ibid.
unreliable and apt to require high levels of maintenance. Utilities would be obliged to provide electrical service to “cover” for the absence of small producers from the grid when their new-fangled gadgetry was being repaired. Moreover, utilities were uneasy about any circumstance in which they lacked direct operating control over cogeneration facilities. Another fear was that cogenerators might default on their contractual obligations to build facilities on time. The menace of unmet demand would loom large. As a result, a utility would have to embark upon a crash program to build its own facilities in time to meet the anticipated demand. This would place a strain on utility resources and/or require additional borrowing on capital markets. Alternatively, expensive power would have to be imported from external sources.

A second set of concerns voiced by utilities in the survey related to threats to utility viability allegedly posed by small producers. First, industries are a utility’s favourite customer. They purchase great amounts of power. If industries cogenerate, they require less utility power. Since utilities depend upon large industrial purchases to defray the high costs of producing electricity, the loss of industrial revenue would shift a greater part of the cost-burden upon the shoulders of non-industrial rate-payers. Steep rate hikes would follow, consumers would naturally shrink from the burden, demand would fall and utilities would end up in financial straits.

It is generally agreed by utilities, small producers and regulatory authorities that any changes in the specific modes by which electricity is generated should not impact unevenly upon utility user groups (residential, commercial or industrial). Coordinated planning strategies must be adopted to ensure that residential users are not hit by disproportionate rate increases.

Utilities also expressed reservations about the long-term availability of small power. They suspected that it was a flash-in-the-pan. New energy technologies or fuel sources (for instance, hydrogen) able to reduce costs within the context of “Big Power’s” established structure would render the small power sector an instant anachronism.

Several respondents suggested that small power production also added an unwelcome complexity to utility long-range planning. The dispersed and decentralized nature of small power production constitutes a challenge to utility planners. But, as stated above, small power’s contribution can easily be considered in aggregate terms. This would make utility planning easier. In any case, decentralized facilities may increase the resilience of utility operations in the face of disruptions of many kinds.

Many of the fears of utilities listed above are speculative in nature. They were expressed at a time when there was in fact no significant small
power production in Canada. In the United States, a rapidly-developing small power sector is overcoming these fears and doubts. System reliability, competition and new technologies are compatible. I propose now to survey the American experience in this field.

IV. The American Experience with Small Power Production

1. The Institutional and Regulatory Framework

Privately owned (stockholders and holding companies) utilities dominate the American electricity sector, accounting for 78.2% of total kwh sales in the U.S. Publicly owned utilities account for 16.4% of total kwh sales in the industry. Rural Electric Cooperatives (RECs) account for only 5.5% of total kwh sales.68

Jurisdiction over the electric industry is apportioned between state and federal regulatory authorities. Section 8 of Article 1 of the U.S. Constitution provides that “The Congress shall have power ... to regulate Commerce ... among the several States.” 69 Consequently, the federal regulatory authority (the Federal Energy Regulatory Commission or FERC) has authority to regulate, inter alia, wholesale interstate sales and transmission of electricity between utilities.70 Moreover, FERC has asserted the right to ensure that “sale" prices paid by utilities for electricity purchased from other utilities are passed on to retail customers in the area served by that utility.71 Given that the industry has become very tightly coordinated through regional "power pools”,72 this is a highly significant power. It is, in fact, virtually impossible to distinguish between interstate and intrastate flows of electricity. The federal government thus exercises broad jurisdiction in this field.

Nevertheless, state regulatory authority applies to intrastate production, sales and local distribution of electricity.73

68. R.S. Handmaker, supra, note 58, at p. 435, n. 1.
69. Article VI of the Constitution provides for the supremacy of federal statutes over state laws-opening the door for specific statutory allocation of other regulatory powers to the federal level.
72. “Power pooling is a voluntary effort to improve the reliability of electricity supply and service, plan for future capacity and to operate efficiently.”: P. Tomain, supra, note 3, at p. 475.
73. Ibid., at p. 452.
2. The Public Utility Regulatory Policies Act

In 1978, Congress enacted the Public Utility Regulatory Policies Act (PURPA) and sparked a revolution in the American electricity business. Essentially, PURPA legislated into existence a new sector of small, non-utility power producers. In doing so, a "free market" wedge was driven into an industry grown comfortable with its status as a "natural monopoly".

a) Background

Before PURPA, many utilities simply refused (and were not obliged) to purchase power from independents or offered to pay only very low rates for their power, rendering the enterprise uneconomical. Utilities also charged independents excessively high rates for standby and supplementary power. "Standby" or "backup" power is provided by utilities to "replace energy ordinarily generated by a facility's own equipment during an unscheduled outage of the facility". Supplementary power may be purchased from a utility when the electricity needs of the facility (or industry cogenerator) demand more power than the facility is able to self-generate.

Independent producers also faced the possibility of being deemed a "utility" and therefore bound by the full panoply of federal and state utility regulations. For instance, in Cottonwood Mall Shopping Ctr. v. Utah Power and Light Co., a private producer was required to apply for and receive a "certificate of public convenience" in order to compete with a utility in providing electricity to a shopping mall. To obtain this certificate, one must establish a need for the provision of services to the area the applicant wishes to serve, show that one's resources are sufficient to support the venture planned, and establish a public interest in the provision of these services. For small producers, the imposition of such paperwork nightmares will often make a venture too expensive and time-consuming to be worthwhile.

75. B.S. Gentry, supra, note 39, at p. 316.
77. Ibid. When the wind dies down, for instance, a commercial establishment powered by a wind turbine will need to call upon the utility's services to continue functioning. That same wind turbine may also not provide sufficient energy during the commercial establishment's busiest periods. The effect of charging a high price for such services makes wind power economically unattractive as an alternative to utility-supplied power.
78. 440 F. 2d 36 (10th Cir. 1971).
79. Ibid.
These factors, coupled with generalized utility resistance (illustrated by their willingness to engage in litigation, lobbying efforts, and so on), precluded the development of a viable small power industry despite the rapid increase in electricity production costs which occurred in the 1970s. In the end, it took PURPA to overcome these barriers.

b) **PURPA's Scheme**

PURPA's purpose was to reduce American dependence on oil imported from foreign sources and to reduce consumption of fossil fuels by, *inter alia*, energy conservation, increased energy efficiency, and increased development of domestic energy resources. The promotion of cogeneration and small power production formed one component of this national energy strategy.

The general thrust of PURPA was to attack the aforementioned institutional and market barriers to small power producer participation in the energy marketplace by: 1) compelling utilities to interconnect with and to purchase electrical energy from cogenerators and small power producers that meet certain specific criteria; 2) prohibiting utilities from charging unreasonably high or discriminatory rates for back-up or supplementary power; 3) precluding the classification of cogenerators or small power producers as utilities and thus exempting them from certain laws and regulations (including the Federal Power Act, the Public Utility Holding Company Act, and state laws and regulations respecting the determination of electricity rates and financial and organizational aspects of utility regulation).

Section 201 is the relevant definitional section of PURPA. A small power production facility is one which produces no more than 80 megawatts of electricity using a primary fuel source of biomass, waste, renewable resources, geothermal resources or any combination thereof. A cogeneration facility is a facility which produces electrical energy and steam or forms of useful energy used for industrial, commercial, heat or cooling purposes. The section also requires FERC to enact regulations

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further defining the characteristics of small power production and cogeneration facilities. Small power and cogeneration facilities meeting FERC requirements are called "Qualifying Facilities" (hereafter "QFs").

Section 210 contains the substantive provisions of PURPA which directs FERC to promulgate rules which require utilities to buy electricity from and sell electricity to QFs at rates which are "just and reasonable" to the consumers of the utility, in the public interest, and are non-discriminating to cogenerators and small power producers. Section 210 also requires FERC to devise a formula to be used in determining rates payable for QF power. No buy-back (purchase) rate may exceed "the incremental cost to the electric utility of alternative electrical energy". The incremental cost of alternative electrical energy is the cost of the electricity the utility would generate or purchase from another source but for the purchase from a QF. These costs are also known as "avoided costs" and FERC requires the rates payable to QFs to equal the avoided costs of the utility.

State regulatory authorities are directed to implement FERC rules implemented under PURPA. QFs are also exempted from certain federal and state laws governing utilities.

c) Effects of PURPA

By any standard of assessment PURPA has been a phenomenal success, especially in developing cogeneration. In 1990, total U.S. cogenerating capacity approached 9,000 mw. By May 1988, would-be producers totalling 67,000 mw of generating capacity had filed applications with FERC for QF status. Of these, contracts for 31,039 mw had actually been completed. One study suggests that, given high fossil-fuel prices and high avoided costs for power, cogeneration capacity may reach 131,600 mw.

85. 16 U.S.C. s. 796 (17)(C), (18)(B). These criteria are set out in 18 C.F.R. ss. 292.203–206 (1987). A qualifying small power production facility must have a capacity of no greater than 80mw; at least 75% of its total energy input must be from the sources stipulated above. Qualifying cogeneration facilities must meet certain efficiency standards. Neither small power production nor cogeneration facilities may be more than 50% owned by an electric utility or an electric utility holding company.
88. 16 U.S.C. s. 824a - 3(b), (d) (1988).
89. 16 U.S.C. s. 824a - 3(d) (1988).
90. 18 C.F.R. ss. 292.304(a)-(b) (1987).
92. 16 U.S.C. s. 824a-3(e) (1988). These laws include the Federal Power Act, the Public Utility Holding Company Act, and "State laws and regulations respecting the rates, or respecting the financial or organizational regulation of electric utilities...".
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by the year 2000.\textsuperscript{93} In terms of small power production facilities using renewable energy sources, applications totalling 16,335 mw of potential generating capacity had been filed with FERC by the end of 1987; at the end of 1985, 6,000 mw had already been built.\textsuperscript{94} In many cases, PURPA-based generating capacity has delayed construction of or led to the cancellation of coal-fired or nuclear baseload plants. PURPA-capacity added nationally in the 1980s has even outstripped new capacity added from "conventional" sources over the same period.\textsuperscript{95} Qualifying facilities now produce over 8% of total American generating capacity.\textsuperscript{96}

The amount of PURPA-based capacity has varied from state-to-state. In California, QFs have built almost all of that state’s new generating capacity in the 1980s.\textsuperscript{97} In Maine, cogenerators and small producers constituted 2% of total generating capacity in 1981; by 1992 that figure will soar to 32%.\textsuperscript{98} In New Hampshire, 223 mw of QF power representing 16% of that state’s peak load has been contracted.\textsuperscript{99} When a 200 mw allotment of generating capacity was offered up for QF purchase in New England in 1988, 73 bids representing a total of 4,729 mw of capacity were received from 57 would-be suppliers.\textsuperscript{100}

However, PURPA’s success has not been evenly distributed. In Illinois, excess generating capacity resulted in low avoided costs for QF production.\textsuperscript{101} Low prices precluded significant QF development.

Under PURPA, state regulatory commissions were obliged to develop and adopt procedures by which the PURPA scheme would be implemented. Typically, state commissions issue a directive to utilities operating within the jurisdiction ordering them to set aside a certain amount of generating capacity (called an “increment” or “decrement”) for purchase by QFs. Each allotment of capacity represents a portion of the utility’s own anticipated load growth which is stripped from the utility and passed over to QFs.\textsuperscript{102}

\textsuperscript{94} C.P. Shea, \textit{supra}, note 53, at p. 46.
\textsuperscript{95} J.W. Griggs, "Competitive Bidding and Independent Power Producers" (1988), 9 Energy L.J. 415, at p. 418.
\textsuperscript{97} C.P. Shea, \textit{supra}, note 53, at p. 45.
\textsuperscript{100} R.F. Naill, et al, \textit{supra}, note 94.
Each decrement carries with it a state-approved rate schedule reflecting the utility's full avoided cost of producing that same block of power. Prospective QFs are invited to submit applications for all or any portion of the block. Applicants are then selected by the utility on the basis of evaluative criteria and procedures which may vary between states. In general, the evaluative criteria focus upon the soundness of a project's conception, adequacy of financial and managerial backing, and anticipated construction and operating costs. The procedures used to aid in ranking and/or selecting applicants may reflect a "first past the post", a "case-by-case", or a bidding-style approach.

d) The Secret of PURPA's Success

PURPA was a boon to the small power production industry in part because it mandated that QFs be paid at a utility's full avoided cost of production even if the QF was able to produce power for less than that amount. In that respect PURPA created a strong financial incentive for alternative energy producers to enter the market and to produce energy as efficiently as possible. With market access now assured, QFs and utilities began to square off over issues of avoided costs.

e) Avoided Costs under PURPA

i) The Role of the States

The crucial role played by state governments vested with the responsibility for implementing PURPA's guidelines should not be underestimated. PURPA stipulated that utilities purchase power from QFs at a rate not exceeding the incremental cost to the utility of alternative electrical energy. FERC interpreted "incremental cost" in terms of "avoided cost" which is defined as the "incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the [QF], such utility would generate itself or purchase from another source". FERC went further and set out various factors to be considered in

103. Ibid., at pp. 11, 12.
104. In theory, bidding systems allow utilities to select the most efficient QF from amongst many would-be suppliers. For a good discussion of the merits and demerits of bidding see B.L. Vanderlinden, supra, note 97, at pp. 1044-45; Central Maine Power, supra, note 98, at pp. 11-12; J.W. Griggs, supra, note 95.
105. B.L. Vanderlinden, supra, note 96, at p. 1012.
determining avoided costs. The relative weight to be assigned to these factors and, most importantly, the determination of the precise rates payable for QF power rested, ultimately, with each state. Some states have given utilities broad discretion in determining avoided costs; others have structured their discretion somewhat by adding additional factors for utilities to consider, while others have developed strict methodologies to be applied by utilities in determining avoided costs. The most "interventionist" states in this respect have tended to be those with policy predispositions favourable to small power. Some states have adopted standard-form contracts to help redress the imbalance of bargaining power between utilities and small producers.

ii) Avoided Cost Methodologies

The proper methodology to be employed in determining avoided costs is the center of considerable controversy.

The most important components of avoided costs are energy (a variable cost) and capacity (a fixed cost). Energy cost savings are realized "when the utility reduces the operating level of any oil, gas, coal or nuclear plant in response to a reduced load induced by the presence of a small producer on the utility system." The amount of energy savings realizable by a utility depends upon the cost of fuel at a given moment and the type of generator burning the fuel. There is clear agreement that energy costs are always part of a utility's avoided costs. There is less agreement, however, on the question of the capacity component. Capacity

108. These factors include, inter alia, the availability of QF power to the utility in terms of: i) "dispatchability" (ease of calling up) of QF power; ii) QF reliability; iii) terms of any applicable contracts; iv) ability to coordinate QF planned interruptions of service with the utility's own planned interruptions; v) usefulness of the QF to the system in emergencies; vi) individual and aggregate value of energy and capacity from QFs on the system; and vii) smaller capacity increments and shorter lead times available from QFs. An additional factor worth noting is "The relationship of the availability of energy or capacity from the QF ... to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use." 18 C.F.R. s. 292.304(e)(2-3).

109. N. Hamilton, supra, note 62, at p. 447-48

110. "California's state government has actively promoted new energy sources. Policymakers...began rewriting the rules governing the state's utility industry even before PURPA had been pieced together in Washington, D.C....the [California Public Utilities] Commission's philosophy is that utilities and independent power producers have an unequal relationship and that careful rules are needed to encourage a competitive new industry." C. Flavin, Electricity's Future (Washington: Worldwatch Instit., 1984), at p. 51. The New Hampshire legislature specifically recognized the need to encourage non-fossil fuel based cogeneration facilities - thus anticipating the possibility that fossil fuel price fluctuations might result in a displacement of renewable-energy based generators. S.P. Voll, supra, note 99.

111. See, e.g., N. Hamilton, supra, note 62.

112. Ibid., at p. 450.
represents a utility's fixed, "sunken" capital investment in generating facilities. Although a FERC regulation makes explicit reference to energy and capacity costs,113 the relative contribution of the capacity component to an avoided cost determination depends upon two further considerations.

First, a utility will be unwilling to allow any (or any significant) capacity payments to be made where there is excess generating capacity in the system. The argument made here is that QF power in this circumstance is not needed and that therefore capacity payments are also unnecessary. One cannot avoid a cost already incurred.114

To this argument small producers reply that excess capacity arises in "lumps" as new capacity is added by a utility. Since excess capacity will disappear in time, QF power will inevitably become necessary. A long-term contract between the QF and the utility can establish an equitable rate schedule having regard to the temporary surplus on the system. In any event, it is at least disingenuous for a utility to maintain its own ambitious building programs to meet future demand while denying any need for QF power.115

Second, utilities argue that the inability of small power technology to provide "firm" (i.e. steady and reliable) power means that utilities must have sufficient capacity "on hand" to substitute for out of service producers; and continue to build new facilities to meet future demand. Again, the claim is that the utility in reality defers less capacity than the small producer appears to be displacing.116

Small producers counter this argument in three ways. First, it is not clear that small producers, considered in the aggregate, are any less reliable (in terms of the reliability of their contribution to the whole system) than any of the large baseload plants a utility operates. It is not uncommon for two 1,000 mw nuclear plants to be shut down simultaneously. Utilities must be able to supply enough electricity from other sources to replace the amount lost. There is no reason why small producers should not be similarly treated.117 Secondly, it is unfair for utilities to expect a higher standard of reliability from small producers' technology than from their own. A certain amount of unpredictability in the system is inevitable. It should be reckoned with and accommodated rather than used as a device to preempt the development of new power

113. 18 C.F.R. ss. 292.304(e), 292.302(b) (1987).
114. B.L. Vanderlinden, supra, note 96, at p. 1025.
116. Ibid.
117. C. Flavin, supra, note 110.
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sources. Thirdly, certain small power technologies are well established and reliable. These include cogeneration and small hydro facilities. Such facilities should therefore be eligible for significant avoided capacity payments. In short, utilities must be willing to take a longer-range perspective on the role that can be played by small producers on the energy stage.

A common tool used by American regulators and utilities to ascertain avoided costs is a hypothetical unit or “proxy plant”. The “proxy” is usually a facility the utility would have built but for the willingness of small producers to generate the same amount of power themselves. The utility may put forth a fairly large, fossil-fuel or nuclear fired baseload plant as the proxy. Alternatively, the utility may put forth a low cost peaking plant (such as a gas turbine) as the proxy. Small producers favour large baseload plants as proxies (capital costs and hence avoided capacity costs) are higher. Utilities favour peaking plants, which feature low capital costs but high fuel costs. (This is why they are only called into service at times of peak demand.) One way of reconciling these approaches to satisfy both parties is to use whichever type of proxy is appropriate in light of the duration of the contract being contemplated for QF power. Since peaking plants have short construction lead times a “peaking proxy” may well be used in calculating short-run capacity credits.

iii) Impact of State “Mini-PURPAs” on Avoided Costs

Under PURPA, states were required to pass legislation (“mini-PURPAs”) embodying the guidelines put forth in the Act. Certain states perceived this requirement as an opportunity for them to further encourage the development of small power production by requiring utilities to purchase QF power at rates in excess of utilities’ full avoided costs. The criteria utilized by regulatory commissions in thus setting rates could be justified (if challenged) by virtue of the independent grant of discretion to set rates for QF purchasers conferred upon regulatory commissions by state legislatures.

118. N. Hamilton, supra, note 62, at p. 452.
119. Various states have opted for one or the other method, B.L. Vanderlinden, supra, note 96, at p. 1026.
120. Ibid., at p. 1027.
122. B.L. Vanderlinden, supra, note 96, at p. 1030. Note that states were also able, under certain circumstances, to set rates at lower than full avoided cost: 18 C.F.R. s. 292.304(b)(3) (1987).
Court challenges to state authority to set rates in excess of full avoided cost have occurred in Kansas and New York. In Kansas, that state’s Supreme Court ruled that states had no right to set such a rate, as FERC had already occupied the field.\textsuperscript{123} FERC’s standard established a statutory maximum rate for purchases from QFs. Absent a waiver granted by FERC to the state regulatory authority exempting the authority from the full avoided cost rule, the statutory maximum rate would apply.\textsuperscript{124}

An inherent ambiguity within FERC’s regulations on this matter became apparent when the New York Court of Appeal upheld that state’s prescribed minimum purchase price of 6 cents/kwh, which was above full avoided costs for some utilities.\textsuperscript{125} In its reasons for judgment, the Court found that PURPA’s avoided cost standard was not an “absolute ceiling” on avoided costs rates set either by federal or state authorities, but rather was meant to put a cap only on rates set by FERC in the context of the federal government’s role in encouraging alternative power.\textsuperscript{126} The Court also cited a FERC explanation of its own regulations to the effect that states were free to set rates which would result in even greater encouragement of alternative technologies.\textsuperscript{127} An appeal of the Court of Appeal’s decision to the U.S. Supreme Court was dismissed for want of a substantial federal question.\textsuperscript{128} As a result, New York’s statute was upheld, but this area of law remains unsettled.\textsuperscript{129}

FERC has itself performed a \textit{volte face}, however, and now considers it impermissible for states to set avoided cost rates in excess of PURPA’s full avoided cost standard.\textsuperscript{130} A multi-state utility, Orange and Rockland Utilities, Inc., had sought a declaration that New York’s statutory minimum rate for QF electricity infringed upon interstate commerce. The utility pointed out that it was interconnected with interstate power grids. Under the utility’s system of allocating wholesale power costs, the costs

\begin{footnotesize}
124. \textit{Ibid.}, at 766-67. A FERC waiver may be granted where an applicant demonstrates that compliance with any requirements of the regulations is not necessary to encourage cogeneration on small power production and is not otherwise required under Section 210 of PURPA: 18 C.F.R. 292.403 (1987). It should also be noted that PURPA also contemplated that QFs and utilities may specifically contract for a power purchase rate lower than the full avoided cost standard: 18 C.F.R. s. 292.301(b)(1) (1987).
130. Re Orange \\& Rockland Utilities, Inc., 92 PUR 4th 1, (FERC 1988). FERC Commissioner Sousa gave a separate concurring opinion at \textit{ibid.}, p. 28; Commissioner Stalon also gave a separate concurring opinion: 93 PUR 4th 364 (FERC 1988).
\end{footnotesize}
of electricity purchased from New York QFs would be partly passed on to out-of-state consumers because the power purchased from those QFs would be shared with subsidiary out-of-state utilities. It was settled law that federal regulatory authority governed interstate sales of electricity. Hence, the utility argued, only PURPA’s avoided cost standard should apply.

FERC agreed, holding that PURPA prohibited states from imposing rates for wholesale purchases of QF electricity in excess of the PURPA-defined standard in the area of interstate commerce. Such rates were “no longer appropriate” because of their “substantial adverse impact on costs to utilities and to consumers”. Moreover, the success of PURPA in encouraging the development of cogeneration meant that rates in excess of the full avoided cost standard were no longer necessary.

However, FERC left open the possibility that states may set rates in excess of full avoided costs if such rates are the manifest expression of a state policy directing the subsidization of certain forms of QF power such as renewable technologies or where changing circumstances (for instance, another “energy crisis”) warrant an urgent effort to quickly add more QF production.

Perhaps in response to criticisms that FERC had inappropriately made use of a complaint proceeding to effect a policy change which should have been made only in accordance with full rule-making procedures, FERC later stayed its order pending the outcome of a rule-making proceeding addressing the issues raised in the Orange & Rockland decision.

The upshot of this decision, if upheld, seems to be that state impositions of rates in excess of full avoided costs are impermissible except, perhaps, in the context of encouraging specific forms of small power production. Underlying this possible loophole or exception is the fact that renewable energy-based small production has begun to lag behind cogeneration as the preferred type of QF for investors.

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131. Ibid., at pp. 15, 31.
132. Ibid.
134. See the dissenting opinion of FERC Commissioner Trabant in Re Orange & Rockland Utilities, Inc., 92 PUR 4th, at pp. 17-28 (FERC 1988).
136. Recall that cogeneration may utilize renewable or fossil fuel. See B.L. Vanderlinden, supra, note 96, at pp. 1034-1037. If the price of fossil fuel is very low, then cogenerators will switch to fossil fuels - defeating PURPA’s purposes.
iv) Can Avoided Costs Reflect Small Power’s Reduced “Externalities?”

The reader will recall my discussion of the “externalities” issue in relation to small power. Costs of electric production not borne by utilities are of several kinds. Readily apparent are social costs resulting from pollution. Additional costs may be those resulting from geopolitical dependency on foreign sources of oil (e.g. military expenditures aimed at securing those sources from disruption), compensating indigenous peoples affected by massive flooding due to hydroelectric projects, or invading scenic areas with power plants and transmission lines. However, efforts to include the avoided social costs of electrical generation have met with little success.

Nevertheless, a good argument may be made to the effect that certain aspects of the PURPA scheme may open the door to the internalizing of now externalized costs in determining rates payable for renewable-energy based small projects.

At present, FERC directs state utility commissions to consider avoided costs attributable both to the reduction of fossil fuel use and to the smaller capacity increments and shorter construction lead times required by small facilities. In terms of the latter criterion the types of costs avoided are those resulting from the greater economic risks inherent to the reliance upon large facilities with long lead-times (cost overruns, financial market changes, undervaluation of electricity rates due to excess capacity when plants are completed, and so on).

Several states already figure certain types of avoided social costs into QF rate schedules. For instance, Virginia’s public utilities commission adds 15% to a utility’s calculated avoided costs based on the societal and environmental benefits realized by increasing the total share of QF production in that state. Commissions in Idaho, North Carolina and New York rank production technologies by the degree of social risk inherent in their deployment. Thus, small hydro projects receive higher avoided cost payments than fossil-fuel or biomass based projects because of the uncertainties of price and supply which beset the latter technologies.

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137. Supra, at p. 537.
138. Ibid., at pp. 1037-38.
139. Ibid.
Whether a particular state's subsidy program violates FERC's new policy stance on QF rates in excess of full avoided costs will depend on the nature of the specific state program impugned by the utility. Should a state commission wish to do so, however, a program implemented to foster specific renewable-energy technologies which include allowances for a broader range of avoided social costs may well survive FERC's scrutiny because FERC has indicated a possible willingness to grant exemptions from its policy for such programs.\textsuperscript{142}

v) \textbf{Avoided Cost Payments: “Just and Reasonable” to Consumers?} QFs may receive a utility's full avoided costs of generation even if the QF is able to produce power for less than that rate. Some critics have attacked this policy as amounting to a subsidization of small power production. Moreover, the additional benefit received by the QF owner above production costs may be in violation of PURPA's own requirement that rates paid for QF power be “just and reasonable” to the utility's consumers.\textsuperscript{143} This argument was considered and rejected by the U.S. Supreme Court in 1983.\textsuperscript{144} In its decision, the Court found that the possibility that rather high prices (viewed through the lens of traditional utility rate-setting concepts such as “just and reasonable”) might be paid for QF power did not automatically invalidate the full avoided cost standard contained in the relevant FERC regulation. Rather, according to the Court, the avoided cost rule was enacted in concordance with FERC's mandate under PURPA to devise a rule which would provide an incentive for the development of small power production and cogeneration.\textsuperscript{145} I mention this decision here in order to illustrate the importance of a clear and express statement of legislative purpose in developing any legislative initiative designed to foster small power production. I will argue later in the paper that the absence of any such purpose in Canadian legislation or policy directives is a stumbling block to increased small power production in Canada.

\begin{itemize}
  \item \textsuperscript{142} The Virginia State Corporation Commission has held that Virginia's 15\% avoided cost allowance for “intangible benefits” accruing from QFs does not violate the \textit{Orange & Rockland} rule: \textit{Re Potomac Edison Co.}, 95 PUR 4th 1 (Va. S.C.C.).
  \item \textsuperscript{143} 16 U.S.C. s. 824a-3(b) (1988). See J.W. Grigg, \textit{supra}, note 95, at pp. 418-22. (The reader will recall that, traditionally, utilities are entitled to receive only a "just and reasonable" rate of return.)
  \item \textsuperscript{144} \textit{American Paper Institute v. American Elec. Power Serv. Corp.}, 103 S. Ct. 1921.
  \item \textsuperscript{145} \textit{Ibid.}, at pp. 1928-30.
\end{itemize}
f) **Increased Competition in the Electricity Market**

The revolution set off by PURPA may be devouring its own children. That is, PURPA may represent only the first step in a progressive deregulation of the electricity-generation business. Some states\(^{146}\) have adopted a mandatory competitive bidding system amongst QFs for available blocks of power. FERC recently sanctioned the adoption of bidding systems by states on a voluntary basis.\(^{147}\) Additionally, FERC has announced plans to enact rules allowing utilities to compete in bidding for increments of generating capacity provided that the power they propose to sell in fact comes from a facility not in their rate base. In response to concerns that QF bids would be overwhelmed by bids from utilities (whose deep pockets enable them to make offers to produce power for less than non-utility QF costs of production) FERC's rules would still obligate utilities to purchase a portion of power needs from QFs.\(^{148}\) These proposals have been extremely controversial.\(^{149}\) From a utility perspective, it is advantageous to be able to compete with QFs. Inefficient utilities, however, will fall victim to market forces. From a small producer perspective bidding is less favourably received because it endangers the guaranteed market conferred upon them by PURPA. From a consumer perspective increased competition may result in lower rates.

g) **Increased Use of Fossil Fuels by QFs**

In the early 1980s energy prices began to fall from the heights attained in the late 1970s. In particular, new supplies of relatively inexpensive natural gas became available. The ability of qualifying cogeneration facilities to use fossil-fuels such as natural gas has led to an increasing displacement of non-fossil fuel based generation in favour of fossil-fuelled facilities built to take advantage of very low-priced fuels. The share of proposed new small power and cogeneration generation that would rely on renewable energy sources is falling, from 29% in 1986 to 12% in 1987. This is ironic in light of PURPA's goals, which were to move away from oil and gas resources, diversify the sources of U.S. energy and encourage

\(^{146}\) For instance: Maine, Vermont, Virginia, New Hampshire and Texas.

\(^{147}\) B.L. Vanderlinden, *supra*, note 96, at p. 1044.


the use of renewable energy sources. What is needed to counteract this tendency is a new regulatory initiative or incentive which would reserve a share of new generating capacity for renewable power sources.

h) Lessons from PURPA

To conclude my discussions of the U.S. experience in small power production I will extract what I perceive to be the basic “lessons” from PURPA. These concern fundamental aspects of small power production and constitute the new ground rules or context for discussions of “alternate” energy sources in Canada.

First, the establishment of a viable small power production industry requires the enactment of ground-breaking legislation as its sine qua non. This industry simply would not have come into existence as it has in the United States without PURPA.

Second, it was essential that PURPA contained a clear and express statement of purpose. By making clear the policy objectives underlying PURPA’s enactment all parties, governmental or otherwise, were compelled to deal with the challenge of small power production in a context defined by PURPA’s objectives. Insofar as PURPA’s objectives reflect the social benefits realizable by the increased use of small power production the achievement of PURPA’s objective means that real benefits accrue to society as a whole.

PURPA has also helped to call into question the fundamental assumptions underlying “business as usual” electricity generation in the United States. “Bigger” does not necessarily always mean “better”. Utilities have been challenged to justify the continued existence of and construction of energy “megaprojects”. In many instances it has been impossible to establish such justification. In a sense then, PURPA has worked to “level the playing field” for all energy producers and has initiated a thorough scrutiny of the true costs of alternate sources of energy.

151. C.P. Shea, supra, note 53, at p. 46. See also J.W. Griggs, ibid., at p. 421.
152. PURPA may have created a "critical mass" of small-power technology and expertise such that the industry itself now generates innovation independently of governmental support.
V. The Canadian Experience with Small Power Production

1. Introduction

Small power production presently makes a very small contribution to the amount of electricity generated in Canada. For instance, small producers are responsible for less than 5% of Ontario’s electrical production, they account for little more than 3% of generating capacity in Nova Scotia and less than 1% of Saskatchewan’s needs. In most provinces, except Ontario, the number of small producers could likely be counted on both hands. In fact, small power production in Canada generated far more theoretical than practical discussion until the mid 1980s.

Nevertheless, more and more potential small producers are beginning to emerge in most Canadian jurisdictions. For example, generating capacity from small producers will increase by over 75% over the next few years in Ontario, Quebec, Alberta and British Columbia. Prodded by legislators, utilities have begun to invite increased involvement with small producers.

The question I wish to consider in this Part of the paper is whether the “lessons” derived from the American experience with small power production can be usefully applied in Canada in order to assist in the development of a viable Canadian small power production industry. To put it another way; “Do we need a Canadian PURPA?” In order to be able to make informed comparisons between the United States and Canada in this area I will proceed by first setting out the regulatory framework of electrical generation in Canada. Second, I will contend that the public utility sector in Canada has been beset by the same structural difficulties now gripping the American utility sector. Third, the existing impediments to small power production in Canada will be outlined.

Only Alberta has passed small power production legislation. As my fourth task I will outline and assess the likely effectivity of this legislation in furthering the growth of small power in Alberta. Reference will also be made to recent energy policy developments in Ontario. The absence of legislation removing entrenched obstacles to small power inhibits its

154. Interview with James McNiven, Dean, Faculty of Management, Dalhousie University., Nov. 7, 1990.
development in Canada. Finally, the issue of electricity pricing will be addressed, with specific reference to recent developments in Nova Scotia.

2. The Regulatory Framework of Electricity Generation in Canada

In Canada, jurisdiction over the field of electricity generation is exercised by the provinces. By s. 92A(1) of the Constitution Act, 1867 the legislature of each province "may exclusively make laws in relation to... c) development, conservation and management of sites and facilities in the province for the generation and production of electrical energy".158

Most Canadian utilities are Crown corporations owned by provincial governments. All Canadian utilities (except Ontario Hydro) are regulated. That is, activities of these utilities are subject to governmental regulatory oversight.159

3. The Crisis of "Big Power" in Canada

As an industrialized country Canada was not immune to the effects of the "oil shocks" of the 1970s. Rising fuel prices, and rising construction costs prompted rate increases which then depressed demand for electricity. Many utilities had to borrow money at high interest rates to finance their projects. As the 1980s began, then, Canadian utilities were caught in a financial maelstrom. Massive debts were incurred; some utilities were barely able to meet interest payments on their debts.160 In Nova Scotia "rate shocks" were averted only by provincial subsidization of power

158. Constitution Act, 1867 (U.K.), 30 & 31 Vict, c. 3. This section was added to the Constitution in 1982. According to Hogg, this provision is declaratory of the pre-1982 law, under which electricity generation was a provincial matter by s. 92(10) of the Constitution Act, 1867 ("local works and undertakings"). P.W. Hogg, Constitutional Law of Canada, (2nd ed.) (Toronto: Carswell, 1985), at p. 597.

159. E.g., see Public Utilities Act, R.S.N.S. 1989, c.380, which sets out the duties of the Nova Scotia Board of Commissioners of Public Utilities over public utilities including the provincial utility (Nova Scotia Power Corporation; see the Power Corporation Act, R.S.N.S. 1989, c. 351).

160. For example, in 1985 the Nova Scotia Power Corporation (NSPC) was able to pay only 70 cents out of each dollar of interest it owed: Between 1980 and 1985 the portion of each revenue dollar needed to finance interest on Canada’s utility debt rose from 33.2 to 42.7 cents - greater than the amount required to service the federal government’s debt. Within that same time period long-term debt for Canadian utility expansion rose from $37.6 to $62.9 billion (67.4% increase); J. Passmore, supra, note 46, at pp. 10-12.
The extent of Canada's energy crisis was revealed by a host of governmental initiatives designed to alleviate Canadian dependency on imported oil. For instance, the federal government's Canadian Oil Substitution Program (COSP) assisted households in converting from oil to natural gas, electricity and renewable energy sources. Increased emphasis was placed on exports and utilizing indigenous resources to generate electricity.

True, provinces with ample hydroelectric power (British Columbia, Manitoba, Quebec) were to some extent shielded from the crunch. Nevertheless, many of the difficulties which beset American utilities also gripped Canadian utilities. Future demand remains uncertain. Cogeneration and "alternate" power sources (which offer short construction lead times and are fuel efficient) are thus increasingly seen as desirable energy options. Yet obstacles stand in the path of alternate energy producers.

4. Economic and Institutional Obstacles to Small Power Production

The precise character of the institutional impediments to the development of small power in Canada may differ from those in the United States. Nevertheless, they have common roots; the entrenched resistance of utilities to perceived encroachments upon their integrity.

Small power producers have generally encountered little difficulty in interconnecting with utilities. However, prices paid for small producer power have tended to be very low while high rates are charged for "backup" or standby utility services. Prices paid for electricity not generated by utilities reflected a general consensus amongst Canadian utilities that only the utility's avoided fuel costs should be taken into account. At the same time, however, the American consensus under PURPA was that avoided costs should include an allowance for both the avoided fuel and capacity costs of the utility.

The monopsonist position of utilities as sole buyers for small producer electricity plus their vastly superior resources (financial and expertise)...
have allowed them to dictate terms to small producers. For instance, in 1983 a private developer acquired the right to develop a small hydro site in Nova Scotia. At first, the Nova Scotia Power Corporation (hereafter called “NSPC”) maintained that the plant’s power was not needed. When the developer persisted in his plan to build the plant NSPC relented only to the extent that it was willing to pay the producer an amount equal to 70% of avoided fuel costs. This latter concession was only gained after the developer appealed to NSPC’s political overseers.168 On another level, Ontario Hydro has consistently used its enormous organizational resources to swamp and stifle dissenters.169

In short, the obstacles faced by small producers in Canada are of two kinds. Economic obstacles exist chiefly in the context of the prices offered for small power and in utility willingness to use its superior resources of information and expertise in order to inflict heavy transactional costs upon would-be producers. Institutionally, obstacles consist in the indifferent or actively hostile stances taken by utilities toward small producers.

The next question to be asked is whether any provincial government has enacted legislation or established a policy which overcomes these obstacles or alleviates their effects.

5. Legislation and Policy
a) Alberta

Only Alberta has passed legislation on small power production. The Small Power Research and Development Act 170(hereinafter “the Act”) and accompanying regulations171 implemented the recommendations of a joint enquiry on small power production held in 1987 by the province’s Energy Resources Conservation Board (E.R.C.B.) and Public Utilities Board (P.U.B.). The inquiry’s recommendations were:

1) that a small power producer of less than 2.5 mw should be classified as a “small power producer” for legal purposes regardless of type of energy used.

2) 100 mw of small power generation should be allowed in Alberta.

3) Utilities should pay for the power on the basis of long-term utility avoided costs.

168. Interview with James McNiven, supra, note 154.
169. See L. Solomon, supra, note 47.
4) Small producers should be exempt from certain regulations applicable to “full status” utilities.

5) The regime was to be reviewed in 1994.\textsuperscript{172}

The Act itself allots 125 mw of generating capacity to small generators using wind, hydro or biomass energy (s. 1(a)(i)).\textsuperscript{173} Small power facilities owned by established public utilities do not fall within the Act (s. 5 of the Reg.). Any projects generating more than 2.5 mw are classified as “pilot projects” (s. 1(a)(ii)(B) of the Act) and are subject to different selection criteria than those applied to capacity projects of less than 2.5 mw.

A prospective small power producer may apply to receive a portion of the allotment by making an application to the Minister (by s. 1(c) of the Act; “a designated member of the Executive Council”). In deciding whether to grant an application for a “small power producer” facility, only a few technical requirements must be satisfied before an initial allotment is granted by the Minister (sections 8, 6 of the Reg.). Rather more stringent criteria (including, \textit{inter alia}, possible social and economic benefits to the province; the nature and availability of the facility’s proposed fuel source; whether the nature of the technology used in the facility would contribute to the advancement of small power production in Alberta; s. 8(2) of the Reg.) apply in the case of “pilot project” applications. Whether a preliminary allotment becomes “final” is contingent upon the success of the producer in negotiating a contract with the utility with whom the producer will interconnect. (There are at least 5 utilities in Alberta.)

The Act clearly represents a cautious attempt to foster an increased role for small producers in Alberta. The Act’s title (“Research and Development”), its classification of certain types of projects as “pilot projects” subject to assessment criteria such as whether it will “contribute to the advancement of small power production in Alberta” and the relatively small size (less than 2.5 mw) of the projects covered by less-stringent assessment criteria testify to the status of the Act as an “experiment”.

\textsuperscript{172} Alta. Energy Resources Conservation Board Commentary, “Small Power”, Canada Energy Law Service (DeBoo, 1990), vol. 3, at p. 30-3113. The program was intended to allow an assessment of the impact of small power on the Alberta Integrated System (AIS).

In light of PURPA, one must certainly wonder whether there is any need to treat small power production technologies as "experimental". PURPA showed that small producers could participate and thrive in the day-to-day functioning of utility systems. The main impediments to small power before PURPA were institutional and economic in nature; not technological (with exceptions such as photovoltaics). Such is also the case in Canada.

Despite the uncertainties that would seem to surround any business enterprise classified as an experiment, there has been no lack of applicants for the 125 mw block of available generating capacity. As of June, 1990, the allotment had been fully subscribed, although only 195 kw of new small producer power is now "on line". 174

At the 1987 Small Power Inquiry which preceded the passage of Alberta’s small power legislation, it was stated that "with a proper policy, projects using renewable resources would be encouraged but should not be given preferential treatment". 175 Several indicators of what constitutes "encouragement" can be found in the Inquiry’s report. Prices paid to small producers would reflect utility avoided fuel and capacity costs 176, calculated by the proxy plant method 177 utilizing a scheme of levelized pricing. 178 Furthermore, small power producers would be exempt from full-blown scrutiny as "utilities". 179 Standard-form utility-small producer contracts would be used. 180 Each of these measures are reasonably positive and are consistent with the spirit of PURPA. In the end, the E.R.C.B. & P.U.B. adopted a price schedule for small power at the high end of a range of proffered rates. 181 These rates have since been increased. 182

The Inquiry, however, stopped short of recommending "special treatment" to small power producers. This entailed rejecting "incentive prices" and refusing to embody "socioeconomic benefits" in buyback rates. Since both measures would impose additional costs upon consumers,

175. ERCB Report 88-A, PUB Report E88001 Small Power Inquiry (Alberta), at p. 5. 176. Ibid...
177. Ibid., p. 10.
178. “Levelized pricing” provides capacity payments to small producers even if, in the short term, only fuel costs are actually avoided. Levelizing smooths out price fluctuations which would otherwise jeopardize the viability of many small enterprises. Ibid., at pp. 12-14.
179. Ibid., at p. 16.
180. Ibid., at pp. 16-17.
182. P. Boyle, supra, note 173, at p. 270.
it was felt that it was more appropriate to leave this sort of subsidization to "direct government initiatives such as taxes or grants".\textsuperscript{183}

The Inquiry's conclusions make it clear that no credit would be allowed for reduced "externalities" and other social costs of production. The same conclusion was reached by Nova Scotia's Board of Commissioners of Public Utilities in a similar hearing held last year.\textsuperscript{184} The onus for recognizing such benefits of small power now clearly lies with the provincial Legislatures.

b) \textit{Ontario}

The New Democratic government of Ontario recently announced a moratorium on further nuclear plant construction by Ontario Hydro.\textsuperscript{185} It is expected that the demand for electricity which would have been satisfied by nuclear power plants will now be met, at least in part, by small producers. This recent policy initiative demonstrates that small power producers may receive an indirect boost through the removal of competitors from markets by means of legislative or executive action.

In the absence of statutory or policy direction from the legislature, small producers must deal with utilities on the latter's terms. The crucial factor involved in utility-small producer relationships is almost always the issue of price.

c) \textit{Prices for Small Power/Avoided Utility Costs}

A significant (relative to the U.S.) small power production sector in Canada does not exist today, mainly due to low avoided costs calculations by utilities.\textsuperscript{186} This is incongruous given the economic efficiencies associated with small power production (especially cogeneration).

In most Canadian jurisdictions, power purchase rates from small producers are less than the cost for the utility to add new base load generation.\textsuperscript{187} Since a new small producer incurs high capital and other start-up costs it is discriminatory for utilities to pay for their power at rates which reflect an averaged cost of their "old", paid for facilities and newer facilities. British Columbia, Alberta and Nova Scotia now base their

\begin{footnotesize}
\textsuperscript{183} Small Power Inquiry, \textit{supra}, note 175, at pp. 5-6.
\textsuperscript{184} \textit{Infra}, at p. 564.
\textsuperscript{185} M. Mittelstaedt, \textit{supra}, note 153.
\textsuperscript{186} J. Passmore, \textit{supra}, note 155.
\textsuperscript{187} In British Columbia the expansion of cogeneration in the forest products sector was discouraged by electricity prices which were less than half the cost of new generation facilities. J.F. Helliwell and A. J. Cox, \textit{supra}, note 64, at p. 250.
\end{footnotesize}
avoided cost calculations upon new capacity avoided. But even these avoided cost rates are not expected to lead to significant new small power generation, at least not in Nova Scotia.\footnote{188} To ascertain why this may be the case, it will be instructive to review a recent decision of the Nova Scotia Board of Commissioners of Public Utilities (hereinafter “the Board”) which outlined the methodology to be used by NSPC in determining an avoided cost rate payable to small producers.

d) The Nova Scotia Hearing

The decision\footnote{189} of the Board was the culmination of a hearing process formally initiated upon an application of NSPC in 1989. NSPC sought to establish criteria and a methodology that would fix prices to be paid to small producers for power supplied to NSPC. The need for making this determination arose after the provincial government publicized its desire to allot a 30 mw block of generating capacity to small producers.

NSPC submitted a proposal which if accepted, would pay small producers an amount equal to NSPC’s estimated avoided cost of adding its own new generating capacity to the system. NSPC chose the “proxy plant” method of estimating avoided costs. This method, commonly used in the United States, “assumes a typical future source of generation for the utility and uses the expected capacity and operating costs of the hypothetical or new plant as a proxy for determining long run incremental costs.”\footnote{190} The specific plant chosen as NSPC’s proxy was a 165mw coal-fired baseload generating facility. Facility costs were calculated over the course of an estimated 33 year operational life for the facility. It should be added here that NPC generated a “spread” of several different cost estimates for the proxy. At the “low end” were figures which approximated the utility’s “least cost” scenario (low fuel costs, no building delays, reliable pollution-control equipment, etc.); at the “high end” were figures representing a high cost scenario. It should also be noted that this method assumes that small producers are entitled to be paid for utility avoided capacity as well as fuel costs.

\footnote{188. Interview with James McNiven, supra, note 154.}
\footnote{189. Decision of the Nova Scotia Board of Commissioners of Public Utilities, In Re - An application of Nova Scotia Power Corp. Relating to the Setting of Rates for Electricity Purchased from Independent Power Producers (hereafter cited as “IPP Hearing”) (August 30, 1990).}
\footnote{190. Ibid., at p. 5.}
i) **Intervenor's Critiques**

Several intervenors appeared at the Hearing to criticize the NSPC proposal. I have grouped their criticisms into "internal" and "external" types of critique. The former relate to flaws inherent in NSPC's proposal; the latter to issues of costs left out of NSPC's proposal.

**Internal criticisms**

The NSPC proposal was premised upon the building of a 3-unit facility. Each unit (i.e., coal-burning generator) would generate 165 mw. Since avoided costs are calculated on a cost/kw basis, the larger the facility, the lower the cost/kw payable as avoided costs. Initial capital costs are high and relatively fixed, regardless of the number of generating units installed. Thus, each "additional" unit increases capital costs marginally while doubling or tripling the facility's electrical output. Extravagant estimates of future output could be made without undue distortion of real costs in the present.

As it turns out, NSPC has no real intention of building the 3-unit plant in the foreseeable future; only a 1-unit plant will be built. Several intervenors suspected that the 3-unit plant was "cooked up" in order to lower the avoided costs payable to small producers.191

The Board rejected this claim on the basis that, even if Units 2 and 3 of the plant were not built there was still reason to believe that growth in demand would soon require the addition of an equivalent amount of generating capacity to the system anyway. The fact that it might be built elsewhere in the province was irrelevant.192 My intention here is to illustrate that utilities may not intentionally act in such a manner as to depress prices paid to small producers. From the small producer's perspective, it nevertheless makes little difference whether such acts are conscious or unconscious.

A second line of internal criticism centres upon the Board's decision to select a rate schedule for avoided costs which reflected a relatively low "least cost" scenario from among the alternative costs schemes submitted by NSPC. Although the reasoning of the Board is hard to decipher on this issue, it is clear that the Board opted for the middle-range cost estimates or arguably, the lower-range set of estimates.193 What are the institutional imperatives at work here?

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191. See, e.g., M. Kilfoil, "Direct Evidence", IPP Hearing, at p. 3.
192. Decision, IPP Hearing at p. 10.
193. Ibid., at p. 8.
On the one hand, the Board believed that if it selected a cost estimate which later turned out to be too high the utility (and thus also rate-payers) would be, in effect, "subsidizing" the small producer. Similarly, such a choice could also be construed as imposing an unfair charge upon the utility and its rate-payers. Since the Board's mandate constrains it from doing either of the above it will invariably opt for a rate schedule within the lower range of predictions. If the estimate proves to be too low, a revised schedule can be adopted later.

Nowhere in this discussion, though, is any consideration given to the level of payment required to sustain and/or develop a viable small power sector in Nova Scotia. To put it simply, there is no requirement in the Public Utilities Act or the Power Corporation Act that avoided cost rates be "fair" or "just and reasonable" to the small power producer. Small producers were the focus of the hearing, yet their needs or interests were not provided for in the legal-institutional framework which structured the hearing. What is clearly needed here is the injection of some sense of purpose, some articulation of the policy considerations which compelled the government to express an interest in small power in the first place (increased efficiency, and so on). By contrast, Alberta's Small Power Inquiry displayed a clear underlying desire to promote small power production.

External Critiques

Prices paid for small power can also be affected by other factors such as subsidies paid to utilities by governments.

ii) Subsidies

A major reason for the inadequacy of present purchase prices is that they do not take into account a variety of "subsidies" and "hidden" benefits received by utilities which effectively obscure the true cost of generating electricity. Essentially, avoided costs would be much higher if utilities had to bear the entire burden of their costs and debts. For instance, public utilities enjoy tax privileges. NSPC, as we have seen, pays no taxes. Small producers pay taxes, and, unlike utilities, do not qualify for federal and/or provincial debt guarantees, low cost loans, or research and development subsidies such as the federal government's Canada Oil Substitution Program (COSP). Many of these programs are "tapped into" by provincial governments on behalf of utilities. Such subsidies are thus intrinsically connected with the status of utilities as government-supported enterprises.

At the Nova Scotia hearing an intervenor protested the receipt by NSPC of "statutory advantages" with respect to land acquisitions; provincial debt guarantees; sale, income and property tax breaks and Cape Breton coal subsidies.\textsuperscript{195} The Board rejected this argument and refused to compensate for these hidden subsidies in avoided costs calculations payable to small producers. To do so, it held, would exceed the Board's mandate to determine whether consumer rates are "just and reasonable". The Board then said, "Any statutory advantages available to NSPC that reduce costs to its customers are a real advantage to customers and setting a rate that would reduce such advantages would be both unjust and unreasonable." Such advantages, the Board mused, "could be offered to NUGs (non-utility generators) if government deemed it to be an appropriate policy".\textsuperscript{196}

The Board's response on this issue was correct, in principle. The implications of including such subsidies in market price determinations carries far-reaching implications for the whole structure of government support for and regulation of particular industries. This was a clear instance of administrative "line-drawing". To go any further would have involved the Board in matters of a policy or legislative nature.

iii) \textit{Externalities}

The Board also rejected arguments that non-utility generators should receive "credit" for the social (referring here to environmental, social, political and the like) costs avoided by utilizing less environmentally harmful, community-based modes of electrical generation. In the Board's view, it was sufficient that NSPC's proxy plant satisfied all existing pollution control laws and regulations.\textsuperscript{197} It seems to me that this characterization of the externalities problem is misleading. It mistakenly identifies the issue of avoided external costs of production and the issue of pollution control. Decreased levels of pollution may result from choosing one mode of electricity production over another. The basic objective of reckoning for avoided external costs of production, however, is not to ensure compliance with pollution control legislation but to aid in determining the overall cost-effectiveness of competing electricity generation options. Compliance with pollution control law undoubtedly results in some avoided social costs. The actual amount of costs avoided by specific generation options, however, may exceed, equal, or fall short of amounts implied by legislated standards. That is, it is not apparent to

\textsuperscript{195} Decision, \textit{supra}, note 189, at p. 21.
\textsuperscript{196} \textit{Ibid.}, at pp. 21, 26.
\textsuperscript{197} \textit{Ibid.}, at p. 22.
me that the fact of compliance with pollution control law bears any necessary relationship to the determination of the actual avoided "external" costs of electricity generation options.

Notwithstanding this interpretive question, the Board's (and the Alberta Inquiry's) conservative position on this issue is understandable given its traditional, narrow mandate to ensure that rates are "just and reasonable" to consumers. Any amount added to a conventional avoided cost tally (that is, one which includes, say, avoided capacity and fuel costs) on the basis of avoided social costs would be perceived as a "subsidy" to small producers and as imposing a needless burden upon rate-payers. 198 Specific legislative or policy guidance will be required before amounts are awarded for the avoidance of such costs. The reader will recall from my discussions of externalities in the context of PURPA that the status of payments made to QFs for the reduction of social costs of production has now become problematic. 199 Within the framework of PURPA, FERC regulations directed states to determine avoided costs having regard to various factors including the reduction of dependence on fossil fuels and the increased system flexibility (shorter lead times; demand responsiveness) gained by using QF power. From a traditional viewpoint even these provisions appeared "radical" and were often thought to be too complex to implement. But at least those provisions were part of the statutory scheme regulators were required to apply. Given a legislature and a regulatory authority favourably disposed to small power production, more "progressive" decisions were made and justified as being within that authority's jurisdiction. Here, however, in the absence of any such statutory direction it would appear to be unwise to expect very much in the way of "progressive" utilities regulation in Nova Scotia.

Summary and Conclusions

Many of the obstacles to small power production identified earlier in the paper are manifest in Canada today. They have had an inhibiting effect on the development of small power production.

Institutional resistance to the inroads of non-utility electricity generation has taken various forms which are more or less overt. A utility may utilize its superior bargaining position vis-a-vis the small producer in order to try to effectively dictate terms to the producer. Discriminatory pricing arrangements for utility purchases of small power producer electricity are common.

198. Note in this context that the rate-payer's interest is not assumed to be identical to the public interest.
199. Supra, at p. 550.
These barriers were recognized, confronted and largely overcome in the United States by PURPA in 1978. There is no statutory equivalent to PURPA in Canada. The Alberta Small Power Research and Development Act represents a cautious step forward but it is unclear that the Act is actually intended to foster small power production on a permanent, commercially-viable basis. The Ontario government’s moratorium on further nuclear development provides indirect support to small producers. Discriminatory pricing arrangements remain problematic. However, even a well-constructed method used for determining rates paid to small producers based on avoided utility generation costs may not be enough to make the industry viable. Subsidies paid to public utilities impede the determination of whether a utility’s real costs of producing electricity are as low as purported. If subsidies were removed, avoided cost rates would rise. The issue of “externalities” is given short shrift by Canadian regulators. This is understandable in view of the absence of any legislative mandate on the basis of which an appropriate allowance for the avoidance of social costs of production could be made by regulatory authorities.

We need a Canadian equivalent to PURPA in each province. Only by such legislation can the entrenched impediments to small power production be overcome and the benefits of small power production be realized. Utilities should not be expected to be agents of change. Regulatory authorities are bound by statutes and doctrines developed in an era geared to the promotion of “Big Power” as a natural monopoly.

Each provincial PURPA would contain several key features. First, utilities would be compelled to purchase small producer power in 50 to 100 mw “decrements” as capacity is added on to the system or obsolete utility-owned units are phased out. Small producers would be paid rates based on full avoided costs reflecting credit for both avoided capacity and energy costs. Avoided social/environmental costs reflecting heretofore externalized production costs would also figure in avoided cost calculations. All forms of small power production (including cogeneration) would be embraced by the statute, removing the distinction presently made between cogenerators and other producers in some jurisdictions (notably Alberta). At the same time, however, special preference in purchase rates might be given to encourage renewable energy based and/or novel highly efficient technologies over those technologies which rely upon and thereby increase our dependence upon fossil fuels. Canadian provinces would thus be able to buck the trend, currently apparent in the United States, towards increased fossil fuel use by small producers and the disproportionate representation of cogenerating QFs.

Most importantly, a provincial PURPA would contain a clear and express statement of its objectives, the foremost of which would be the
promotion of small-scale, non-utility electricity generation. Other objectives would include the reduction of dependence upon fossil fuels, nuclear energy, and so on.

The same policy objectives could also be realized by simply amending present “enabling” statutes governing the functions of provincial utility boards. Such amendments would make conservation, energy efficiency, the promotion of small power, and reduction of fossil fuel use a part of the mandate of these boards. Such recognition of heretofore irrelevant considerations could make the crucial difference in the next round of avoided cost calculations for small-power producers between a too-low and an adequate small power purchase rate.

Finally, certain measures (statutory or policy-based) might be taken which would complement both of the aforementioned legislative options. Such measures would remove the dense, opaque layers of government (federal and provincial) subsidies currently swaddling public utilities. They might also effectively promote small power by removing competitors of small producers such as nuclear power.