

**SB**

**277**



March 18, 2010

The Honorable Lesil McGuire  
Alaska State Senate  
Alaska State Capitol, Room 125  
Juneau, Alaska 99801

Dear Senator McGuire:

I appreciate the opportunity to respond to the criticisms and concerns raised in its letter dated March 8, 2010, by the Alaska Power Authority (APA) regarding Senate Bill 277, on behalf of Cook Inlet Region, Inc. (CIRI) as a potential independent power producer (IPP). While I will respond in a point-by-point fashion I will start with a higher level response that the APA's criticisms are generally a misunderstanding of the relationship between IPPs and their regulated public utility customers.

The APA fundamentally misunderstands the respective roles of an IPP and its utility customers, and the resulting relationship. Unlike a regulated public utility that has a certificated, monopoly service area granted by the Regulatory Commission of Alaska (RCA), an IPP has only wholesale customers obtained by arms-length commercial negotiations. The resulting differences are profound.

The essence of the issue is that Alaska has very few for-profit entities involved in the development and operation of electric power projects, and even fewer IPPs. The emergence of IPPs developing renewable energy projects has raised the possibility of a different model of developing projects in Alaska. Most of the comments in the APA's letter either result from a misunderstanding of the relationship between IPPs and their public utility customers or reflect an apparent mistrust of anything that is not a cooperative or municipally-owned public utility. We believe that the exemption proposed by SB 277 encourages and supports negotiated and commercially-reasonable relationships between IPPs and public utilities, and, as such, is good public policy.

I will now address the specific, numbered concerns raised in the APA's letter.

#### General Concerns

1. The exemption proposed by SB 277 is necessary.

Obtaining a Qualified Facility designation under federal law does not simply provide an exemption from state regulation. A QF designation also provides the IPP with a default option of putting power onto public utilities in a non-consensual

manner by selling to the utilities at avoided cost. CIRI does not believe that it would be appropriate or desirable to enter a market as small as Alaska's Railbelt in a non-consensual manner, even if it is possible under federal law. Moreover, the promise of renewable energy is to decouple the cost of power from the cost of fuel over time ultimately making renewable power cheaper than its fuel-fired alternative. Selling renewable power at avoided cost does not pass this promise on to the ultimate ratepayer. Perversely, selling renewable power at avoided cost allows an IPP to keep that benefit as profit, something you would think the APA would not suggest as its preferred public policy.

The option of applying to the RCA for a regulatory exemption is also an undesirable and impractical option for several reasons. The RCA has shown itself to be a slow, expensive and unpredictable regulatory body. Unlike public utilities who can recover the expense of their RCA practice in their respective rate bases and who have a state-sponsored monopoly against which to pursue project development, IPPs often have limited market windows in which to put together all of the necessary pieces to successfully develop private power projects, including successful negotiation of one or more power purchase agreements. The uncertainty, delay and expense of asking for a project exemption from the RCA layers an additional and significant project risk on private project development.

More importantly and fundamentally, however, the RCA has shown itself to be a partial and biased forum in which to seek the exemption from regulation for a project sponsored by a private, for-profit project proponent. A sitting RCA commissioner has privately questioned CIRI's motives in supporting SB 277 and has surmised that CIRI's motivation is trying to obtain out-sized returns—implying that being a for-profit entity makes CIRI an untrustworthy project proponent. Similarly, staff for the RCA has publicly testified in a prior Senate committee hearing on SB 277 that exempting a private, for-profit project from direct regulatory oversight could never be in the public interest, or words to that effect. These recent public and private sentiments demonstrate that the RCA is a potentially biased body from which a fair and impartial hearing cannot be obtained by a private, for-profit project proponent.

For these reasons, neither the federal QF nor the state RCA processes provides a reasonable and acceptable manner in which to exempt a IPP-sponsored renewable energy project from RCA regulation.

2. The fact that the RCA cannot second-guess the results of a commercial, arms-length negotiation between an IPP and a public utility is precisely the reason the exemption proposed by SB 277 is necessary. It is the public utility's job to ensure that the contract's rates, terms and conditions of service are fair and commercially reasonable. And it is a role that the public utilities are capable of fulfilling. It is unnecessary and unfair for an IPP, who bears all of the project development risk, to

have to negotiate a commercial PPA with one or more utilities and then start over with a regulatory process in the RCA that can take up to 18 months to complete.

It is also inappropriate to suggest that the RCA, and thereby any other interested party because of the public nature of RCA proceedings, must have access to all documents and costs of a project in order to satisfy the public interest. Again, the role of validating costs and justifying returns is best handled in a commercial negotiation. The second guessing and potential gaming of comments and motives in the RCA process only serves to drive up delay, expense and risk after the conclusion of negotiations between the IPP and the public utilities.

3. The RCA is not a necessary forum in which to adjudicate disputes between an IPP and public utility. There are numerous alternative dispute resolution methods, such as mediation and arbitration, that can provide for timely and expert adjudication of disputes short of filing lawsuits in court.
4. The "obligation to serve" is inappropriate to apply to a IPP-sponsored project because it is a concept that derives from the monopoly service territory granted to public utilities. Suggesting that a private project should have an "obligation to serve" shows that the APA fundamentally does not understand the relationship between an IPP and its public utility customers.

Taking the APA's suggestion that IPP-sponsored projects should have an obligation to serve at its literal face-value would mean that the project could not refuse to provide service to any inter-connected public utility. How would this work? Does this mean that the IPP would have an obligation to serve any interested public utility but would not have any contract negotiation mechanism to arrive at a workable relationship? Obviously, this would not work.

5. The financial fitness of an IPP is a matter that should be addressed by the purchasing public utility. If that utility does not believe that the IPP is sufficiently capable of developing and operating the project for any reason—financial, technical or operational—then that utility can refuse to purchase the project's power. Layering the RCA over the top of this process implies that the public utilities are incapable of protecting themselves through due diligence and contract negotiations. Moreover, the APA's reference to the "fit, willing and able" standard again misapplies the public utility, monopoly standard of operation to the IPP concept. The "fit, willing and able" standard applies to public utilities because of their state-granted monopoly service territories. Implicit under that standard is a public utility's capacity and competence to determine the fitness of and negotiate the commercial purchase of power generated by others, including IPPs. It is surprising that the APA would suggest that its own membership (comprised of public utilities) is incapable of performing one of the core competencies within their own respective certifications as public utilities.

The suggestion that the RCA provides additional comfort in a bankruptcy situation is a red herring. The bankruptcy statutes provide for the bankruptcy court and bankruptcy trustee to protect the public interest. To suggest otherwise is simply a scare tactic intended to illicit the fear of the lights going dark because of the financial insolvency of an IPP. This is not a realistic scenario. The APA's motives are further illustrated by the suggestion that developing a project in a subsidiary entity is inappropriate—"owner" is not a dirty word when it describes a subsidiary entity used to develop and own a project and to suggest otherwise is simply an indirect way to slander private, for-profit entities.

6. The APA's suggestion that the affected utilities must be able to comment on a PPA post-negotiation is precisely why the exemption proposed by SB 277 is necessary and appropriate. Allowing a utility that has negotiated a PPA to later come back through the regulatory process to renegotiate the contract suggests that bad-faith negotiations and gaming are an appropriate business practice. We do not agree. To suggest that other non-contracting utilities have some basis for reviewing and commenting on PPAs to which they are not a party is to invite the sort of regulatory busy-body filings that drive up the cost, delay and uncertainty of the RCA process.

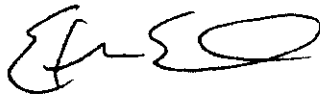
#### Specific Concerns

1. The 65 megawatt size limit is not too large. The APA suggests that a 500 kilowatt limit is appropriate. While we agree that a .5 megawatt facility should be exempted, we believe that larger facilities should be exempted as well. IPPs need a predictable and fair process to negotiate for the commercial sales of their project power. Without predictability and fairness, the status quo—no IPPs on the Railbelt and no large commercial-scale renewable projects will likely persist.
2. The APA's suggestion that an IPP could cherry pick other non-electric utilities as customers is unrealistic. How would an IPP deliver the power to its non-electric utility customer without negotiating a transmission agreement with the existing electric utility? And how would the IPP deliver firm power (as opposed to the intermittent power produced by renewable power sources) without negotiating a firming agreement with the electric utility? These points illustrate the APA's principal concern: competition. CIRI believes that the discipline, efficiency and market competition demanded of IPPs, as for-profit enterprises, bring benefits to the cost of power and ultimately to the ratepayer. The APA obviously disagrees and prefers non-competitive, government-sponsored monopolies.
3. The APA again raises the "obligation to serve" notion addressed above. I will not address it again.

4. This point is a permutation of the "obligation to serve" point again. But it also raises for the first time the possibility of an IPP owning a regulated entity. The RCA already possesses the ability to look through ownership structures to sister and parent companies of regulated utilities. Thus, the RCA already possesses the authority and tools to address this potential issue.
5. This point highlights an APA inconsistency. In the General Concerns point number one, the APA suggests that an IPP can get certified as a Qualified Facility under federal law in arguing that SB 277 is unnecessary. In this point, it decries the "contentious experiences" of utilities who had to deal with developers who were attempting to force them to purchase power in a non-consensual manner—a veiled reference to the very QF program it suggests above as an available alternative. As stated above, we agree that non-consensual power sales are not in the ultimate interest of Alaska's public utilities. The exemption proposed by SB 277 fosters negotiated and consensual power sales between IPPs and incumbent utilities. This is exactly the point.

Sincerely,

Cook Inlet Region, Inc.



Ethan Schutt  
Senior Vice President, Land and Energy Development



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March 8, 2010

Senator Lesil McGuire  
Alaska State Legislature  
120 4<sup>th</sup> Street, State Capitol, Room 125  
Juneau, AK 99801-1182

Re.: Senate Bill 277

Dear Senator McGuire:

The Alaska Power Association (APA) and its members have not yet had the opportunity to fully explore all of the potential impacts of the March 2, 2010, committee substitute for Senate Bill 277. However, based on its preliminary review, APA is concerned about the potential ramifications of this bill. At this point, APA cannot support SB 277 because of those concerns, but welcomes any opportunity to discuss those concerns with you or your staff. APA's concerns are summarized below:

**General Concerns Regarding Statutory Exemption:**

1. The exemption from RCA certification and regulation provided for in the bill may be unnecessary for the following reasons: First, under federal law, most renewable energy resource electric generation facilities that propose to sell power only to another electric utility can already become exempt from state regulation by becoming a "qualifying facility" ("QF"). See 18 C.F.R. § 292.602(c); 18 C.F.R. § 292.601(a), (b). Such facilities include all QFs that are a cogeneration facility, a geothermal or biomass small power production facility, or any other small power production facility (including hydroelectric, solar, and wind-power facilities) having a capacity of 30 megawatts (MW) or less. In general, all of the types of renewable energy resources facilities referenced in the bill would be eligible to become a QF. Such a facility can become a QF through a simple self-certification with FERC.

Second, regardless of whether a renewable energy resource facility is exempt as a QF, the facility can also become exempt from RCA certification and regulation through a petition to the Regulatory Commission of Alaska (RCA) that demonstrates that the exemption is "in the public interest." See AS 42.05.711(d). In 2009, two small hydroelectric facilities obtained public interest exemptions from the RCA based on the facility's generation source and small size, the fact that the facility would sell power only to an electric utility, and the cost and burden of certification and regulation. See RCA Order Nos. U-08-102(2) and U-08-132(2) (attached).

2. The proposed statutory exemption would impair the RCA's ability to ensure that the facility's rates, terms, and conditions of service are just, reasonable, and non-discriminatory, particularly when the facility sells power to multiple electric utilities. Although the RCA would have to approve the purchasing utility's entering into a power purchase agreement with the facility, that so-called "indirect regulation" of the exempt facility would not give the RCA full access to the facility's cost and financial information.

3. The proposed statutory exemption would divest the RCA of jurisdiction to adjudicate complaints by the purchasing electric utility against the facility for failing to provide adequate, non-discriminatory service. In addition, if the facility were regulated and a dispute arose regarding a rate issue or service issue that the facility and the purchasing electric utility did not clearly contemplate in their long-term power purchase agreement, the RCA would have jurisdiction to resolve that dispute. Without RCA jurisdiction, the purchasing electric utility would be limited to filing a lawsuit in court to address those types of issues, which involves significantly more cost and delay (and less adjudicator expertise over the subject matter) than a complaint filed with the RCA.

4. RCA certification of a renewable resources facility imposes an "obligation to serve," which ensures that the facility cannot unreasonably refuse to provide service to a particular customer. The broad exemption proposed under the bill would preclude the RCA from enforcing such an obligation, thus allowing the facility to discriminate among potential power purchasers.

5. If a renewable resources facility is certificated and regulated by the RCA and the facility seeks bankruptcy protection, the RCA generally would have standing in the bankruptcy proceeding to help ensure that the public interest is protected. That measure of protection would not exist if the facility is categorically exempt from RCA jurisdiction by statute. That issue can be significant because a renewable energy resources facility may be (and likely will be) owned by a subsidiary corporation or subsidiary limited liability company in such a way that the

effective, ultimate "owner" of the facility is shielded from all liability for the debts and obligations of the facility. That is one of the reasons that the RCA carefully considers whether the legal owner of a proposed public utility is, in fact, "fit, willing, and able" to provide public utility service when the RCA decides whether to certificate the utility, or when the RCA decides whether to grant a public interest exemption from regulation. Under the broad exemption provided for in the bill, the RCA would lack jurisdiction to review such matters, particularly after the purchasing electric utility obtains RCA approval of the power purchase agreement.

6. The proposed statutory exemption would preclude affected electric utilities from having input regarding whether the exemption of a particular facility is justified. The existing RCA public interest exemption process allows utility input and public input and allows the RCA to determine on a case-by-case basis whether the facts and circumstances justify exemption for a particular facility. Related to that, until a power purchase agreement and the associated rates, terms, and conditions of service are negotiated regarding a particular facility, the utilities that are intended to purchase power from the facility may not have enough information to know whether an exemption from RCA certification and regulation is justified. The broad statutory exemption provided for in the bill would preclude affected electric utilities from making that determination when the facts and circumstances associated with a particular facility are known.

7. There has not been adequate time for APA and its members to fully explore all of the unintended consequences of the type of broad, absolute exemption provided for in the bill.

#### **More Specific Concerns Regarding SB 277:**

1. The bill's 65 MW size restriction appears to be too high. The potential justification for exemption from RCA certification and regulation is very different if the exemption applies to a small 500 kilowatt (kW) renewable resources facility as opposed to a large 65 MW facility.

2. The bill would exempt a facility that sells its output to *any type* of regulated public utility, not just to a regulated *electric* public utility. That would allow the exempt facility to compete against the local electric utility for firm electric sales to non-electric utilities that are within the local electric utility's certificated service area.

3. The bill would exempt a facility that sells its output to *multiple* regulated electric utilities. Sales to multiple electric utilities raise concerns about preventing the facility from discriminating among customers with respect to rates, terms, or conditions of service.

Senator Lesil McGuire

March 8, 2010

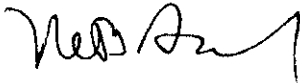
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4. The bill would exempt a facility even if it is closely affiliated with a regulated electric utility to which it sells power. That raises additional concerns about the potential for discriminatory preferences among the electric utilities that purchase power from the facility.

5. The bill would exempt cogeneration facilities because "renewable energy resources" under AS 42.45.045(l) include "wasteheat recovery." Electric utilities have had contentious experiences with developers attempting to force the utility into uneconomic power purchases from proposed cogeneration plants.

Again, APA and its members have had only a limited amount of time to attempt to review the potential ramifications and unintended consequences of SB 277. APA and its members will continue their review of the bill and may have other concerns as they review it in greater detail. In the meantime, APA stands ready to discuss its concerns with you or your staff whenever is convenient for you. We suggest you initiate a meeting with all interested parties as soon as possible so that we can have a discussion of all the issues.

Sincerely,



Marilyn Leland  
Executive Director

# ALASKA STATE LEGISLATURE

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Senate Resources Committee

Member  
Senate Judiciary Committee

## SENATOR LESIL MCGUIRE

### Sponsor Statement for Senate Bill 277

**"An Act exempting from regulation by the Regulatory Commission of Alaska and by municipalities generators of electricity from renewable energy resources that sell electricity to regulated utilities."**

The electric demand of the relatively small and dispersed population in Alaska has traditionally been served by regulated utilities. The Regulatory Commission of Alaska (RCA) is charged with certifying utilities, regulating their rates, resolving disputes and protecting consumers. Throughout most of the State, electric utilities are not-for-profit and/or member owned cooperatives that serve a defined geographic area and customer base. Regulation of these utilities, given their monopoly status may certainly be appropriate.

However, regulation can pose obstacles to investment. In many states, the generation of electricity has been deregulated in order to provide an avenue for private sector investment in the sector. In a traditionally regulated model, the investment risk is born by ratepayers where in a deregulated environment the risk is born by investors. In markets that have been deregulated, investment in renewable energy is significantly higher than in strictly regulated markets. A study by the U.S. Energy Information Administration shows that the annual growth of renewable penetration in restructured electricity markets is 11.3% while it is a mere .6% in highly regulated markets. Recognizing the regulatory impediment to the development of renewables, the Federal government has provided avenues for renewable generators to escape state regulation through an application to the Federal Energy Regulatory Commission.

Senate Bill 277 attempts to find a middle ground between a thoroughly deregulated market and the highly regulated environment in Alaska. SB 277 exempts renewable generation from RCA regulation only if the power is sold to a regulated utility. This compromise maintains RCA oversight over the power sales agreements and thereby provides a layer of protection to ratepayers. SB 277 opens Alaska's electricity market to private sector investment in renewables and will encourage investment in a cleaner energy future for Alaska.

# ALASKA STATE LEGISLATURE

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Senate Special Committee on Energy  
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Senate Judiciary Committee

## SENATOR LESIL MCGUIRE

### Changes to SB 277 in CS SB 277: 26-LS1353\P

The changes to SB 277 in CSSB 277 are found in section 3 of the bill. The following changes were made to limit the exemption from RCA regulation provided by section 3. More broadly the exemption has been limited to the plant rather than the person. Specifically, the following limits apply in the P version:

1. The plant must be placed in service before January 1, 2016.
2. The plant may not generate more than 65 megawatts of electricity.
3. The person that owns the plant does not receive tax credits related to electricity generation or grants for the generation from the state.

# LEGAL SERVICES

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## MEMORANDUM

February 12, 2010

**SUBJECT:** Definition of "public" in AS 42.05  
(Work Order No. 26-LS1353\E)

**TO:** Senator Lesil McGuire  
Attn: Mike Pawlowski

**FROM:** Brian J. Kane *BJK*  
Legislative Counsel

You have asked the following: For the definition of "public" or "general public" found at AS 42.05.990(3), does that definition include all three subparagraphs, (A), (B), and (C), so that all three must be satisfied to mean "public"? Or, are (A), (B), and (C) three different options for the meaning of "public," as in (A) or (B) or (C)?

Generally speaking, "and" should be used as a conjunctive and "or" as a disjunctive. Under ordinary circumstances, the literal meaning of the words "and" and "or" should be applied unless the literal meaning makes the statute inoperable or it becomes questionable. *Sutherland Statutory Construction*, sec. 21:14 (7th ed.). In the case at hand, though, it seems that using the word "and" as a conjunctive brings the subparagraphs in the definition into conflict. Assuming that all three things are required for the definition of "public," then you have a scenario where there is (1) a group of 10 or more customers, (2) one or more customers, and (3) a utility purchasing the product. If all three of these are a part of "public," then it is quite difficult to think of a situation where this definition would actually apply. On the one hand you are dealing with customers purchasing from a utility, and on the other hand you have a utility purchasing

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<sup>1</sup> In full, AS 42.05.990(3) reads: (3) "public" or "general public" means

(A) a group of 10 or more customers that purchase the service or commodity furnished by a public utility;

(B) one or more customers that purchase electrical service for use within an area that is certificated to and presently or formerly served by an electric utility if the total annual compensation that the electrical utility receives for sales of electricity exceeds \$50,000; and

(C) a utility purchasing the product or service or paying for the transmission of electric energy, natural or manufactured gas, or petroleum products that are re-sold to a person or group included in (A) or (B) of this paragraph or that are used to produce the service or commodity sold to the public by the utility.

Senator Lesil McGuire

February 12, 2010

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electricity to sell to a customer. These cannot both occur at once in order to fulfill the definition. Using the term "and" as a conjunctive appears to make this definition inoperable, as best I can surmise. Therefore, it appears that the second option for the definition that is offered is the correct interpretation for the definition of "public." Hence, the term "public" means (A), or it means (B), or it means (C).

In relation to the definition for "public utility" -- which has the line "furnishing, by generation, transmission, or distribution, electrical service *to the public* for compensation" -- you can, assuming that "and" is disjunctive, read "public" to mean any one of the three options available in (A), (B), or (C), which offers a more expansive inclusion into this section than a reading requiring all three paragraphs to be met.

The definition in question was amended in 1990.<sup>2</sup> Prior to 1990, the definition read as follows

(3) "public" or "general public" means

(A) any group of 10 or more customers that purchase the service or commodity furnished by a public utility as defined in (4) of this section; and

(B) any utility purchasing the product or service or paying for the transmission of electric energy, natural or manufactured gas, or petroleum products which are re-sold to a group included in (A) of this paragraph or which are used to produce the service or commodity sold to the public by the utility.

With only two parts to the definition, it seems clearer that "public" either means what is described in (A) or it means what is described in (B). To fall under the definition of public, there does not have to be a scenario where there is a group of 10 or more customers *and* any utility purchasing the product. If that was the proper reading, then finding an entity that met that criteria would be very difficult. The change in the definition that occurred in 1990 added one more subparagraph to the definition (now (B)). Adding this third subparagraph did not change the definition to mean that the term "public" had to include all three paragraphs to be considered "public."

In conclusion, it appears that the term "public" can have the meaning listed in AS 42.05.990(3)(A) or (3)(B) or (3)(C) -- it does not have to meet all three at once. However, amending the definition to change the "and" to an "or" would relieve the definition of controversy.

If I may be of further assistance, please advise.

BJK:ljw  
10-087.ljw

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<sup>2</sup> The amending language can be found at sec. 4, ch. 140, SLA 1990.

# LEGAL SERVICES

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## MEMORANDUM

February 16, 2010

**SUBJECT:** Independent power producer (Work Order No. 26-LS1353\E)

**TO:** Senator Lesil McGuire  
Attn: Mike Pawlowski

**FROM:** Brian J. Kane *BJK*  
Legislative Counsel

As a follow-up to the memorandum I sent to your office on February 12, 2010, you have asked: If an independent power producer sells to less than 10 customers, would it be a utility and therefore subject to regulation under AS 42.05?

Assuming that the definition of "public" or "general public" in AS 42.05.990(3) is being read as (A) or (B) or (C), then the answer to your question is that it is possible the independent power producer described could be subject to regulation. AS 42.05.990(3) has an option for the definition of "public" that reads:

(B) one or more customers that purchase electrical service for use within an area that is certificated to and presently or formerly served by an electric utility if the total annual compensation that the electrical utility receives for sales of electricity exceeds \$50,000;

If an independent power producer has one or more customers but fewer than 10 *and* meets the other requirements of the definition in (B) -- namely receiving sales of electricity that exceed \$50,000 -- then the independent power producer would be regulated under AS 42.05 since it sells to the "public." However, if the producer sells to fewer than 10 customers and does not exceed the \$50,000 sales mark, then that producer is not subject to regulation under AS 42.05, as the producer would not be selling to the public, which is a requirement of AS 42.05.990(4)(A) to be a public utility.

BJK:ljw  
10-101.ljw

## Applicable RCA Statutes

Sec. 42.05.175. Timelines for issuance of final orders.

(a) The commission shall issue a final order not later than 180 days after a complete application is filed for an application

- (1) for a certificate of public convenience and necessity;
- (2) to amend a certificate of public convenience and necessity;
- (3) to transfer a certificate of public convenience and necessity; and
- (4) to acquire a controlling interest in a certificated public utility.

(b) Notwithstanding a suspension ordered under AS 42.05.421, the commission shall issue a final order not later than 270 days after a complete tariff filing is made for a tariff filing that does not change the utility's revenue requirement or rate design.

(c) Notwithstanding a suspension ordered under AS 42.05.421, the commission shall issue a final order not later than 450 days after a complete tariff filing is made for a tariff filing that changes the utility's revenue requirement or rate design.

(d) The commission shall issue a final order not later than 365 days after a complete formal complaint is filed against a utility or, when the commission initiates a formal investigation of a utility without the filing of a complete formal complaint, not later than 365 days after the order initiating the formal investigation is issued.

(e) The commission shall issue a final order in a rule-making proceeding not later than 730 days after a complete petition for adoption, amendment, or repeal of a regulation under AS 44.62.180 - 44.62.290 is filed or, when the commission initiates a rule-making docket, not later than 730 days after the order initiating the proceeding is issued.

(f) The commission may extend a timeline required under this section if all parties of record consent to the extension or if, for one time only, before the timeline expires, the

- (1) commission reasonably finds that good cause exists to extend the timeline;
- (2) commission issues a written order extending the timeline and setting out its findings regarding good cause; and
- (3) extension of time is 90 days or less.

(g) The commission shall file quarterly reports with the Legislative Budget and Audit Committee identifying all extensions ordered under (f) of this section during the previous quarter and including copies of the written orders issued under (f)(2) of this section.

(h) If the commission does not issue and serve a final order regarding an application or suspended tariff under section (a), (b), or (c) of this section within the applicable timeline specified, and if the commission does not extend the timeline in accordance with (f) of this section, the application or suspended tariff filing shall be considered approved and shall go into effect immediately.

(i) In adjudicated docket matters that come before the commission under state law or federal law and are not subject to a timeline under federal law or (a) - (e) of this section, the commission shall issue a final order not later than 180 days after the filing of an initiating petition. If the matter is commenced on the commission's own motion, the commission shall issue a final order not later than 365 days after the issuance of an order opening the docket. This subsection does not apply to a complaint against a utility, a petition to revoke a certificate of public convenience and necessity, or a functionally equivalent filing.

(j) If the commission does not issue and serve a final order governed by (i) of this section within the applicable timeline specified, including any extension granted by the commission in accordance with (f) of this section, the initiating petition shall be considered approved and shall take effect immediately, or, if the matter was commenced by the commission, the docket shall be closed with no action taken.

(k) If proceedings subject to different timelines under this section are consolidated or if a single proceeding implicates more than one timeline, the latest applicable deadline for the issuance of a final order shall apply.

(l) The commission may not evade the requirement of this section by terminating a proceeding in a docket and opening a proceeding in another docket on substantially the same matter.

(m) For purposes of this section, "final order" means a dispositive administrative order that resolves all matters at issue and that may be the basis for a petition for reconsideration or request for judicial review.

(n) For purposes of this section, an application, tariff filing, formal complaint, or petition is complete if it complies with the filing, format, and content requirements established by statute, regulation, and forms adopted by the commission under regulation.

## Article 02. CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY

### Sec. 42.05.221. Certificates required.

(a) A public utility may not operate and receive compensation for providing a commodity or service without first having obtained from the commission under this chapter a certificate declaring that public convenience and necessity require or will require the service. Where a public utility provides more than one type of utility service, a separate certificate of convenience and necessity is required for each type. A certificate must describe the nature and extent of the authority granted in it, including, as appropriate for the services involved, a description of the authorized area and scope of operations of the public utility.

(b) All certificates of convenience and necessity issued to a public utility before July 1, 1970, remain in effect but they are subject to modification where there are areas of conflict with public utilities that have not previously been required to have a certificate or where there is a substantial change in circumstances.

(c) A certificate shall be issued to a public utility that was not required to have one before July 1, 1970, and that is required to have one after that date, if it appears to the commission that the utility was actually operating in good faith on that date. Such a certificate is subject to modification where there are areas of conflict with other public utilities or where there has been a substantial change in circumstances.

(d) In an area where the commission determines that two or more public utilities are competing to furnish identical utility service and that this competition is not in the public interest, the commission shall take appropriate action to eliminate the competition and any undesirable duplication of facilities. This appropriate action may include, but is not limited to, ordering the competing utilities to enter into a contract that, among other things, would:

- (1) delineate the service area boundaries of each in those areas of competition;
- (2) eliminate existing duplication and paralleling to the fullest reasonable extent;
- (3) preclude future duplication and paralleling;
- (4) provide for the exchange of customers and facilities for the purposes of providing better public service and of eliminating duplication and paralleling; and
- (5) provide such other mutually equitable arrangements as would be in the public interest.

(e) If the commission employs professional consultants to assist it in administering this section, it may apportion the expenses relating to their employment among the competing utilities.

(f) *[Repealed, Sec. 12 ch 136 SLA 1980].*

*Sec. 42.05.230. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

**Sec. 42.05.231. Application.**

Application for a certificate shall be in writing and shall be in the form and contain the information required by the commission by regulation.

*Sec. 42.05.240. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

**Sec. 42.05.241. Conditions of issuance.**

A certificate may not be issued unless the commission finds that the applicant is fit, willing, and able to provide the utility services applied for and that the services are required for the convenience and necessity of the public. The commission may issue a certificate granting an application in whole or in part and attach to the grant of it the terms and conditions it considers necessary to protect and promote the public interest including the condition that the applicant may or shall serve an area or provide a necessary service not contemplated by the applicant. The commission may, for good cause, deny an application with or without prejudice.

*Sec. 42.05.250. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

**Sec. 42.05.251. Use of streets in municipalities.**

Public utilities have the right to a permit to use public streets, alleys, and other public ways of a municipality upon payment of a reasonable permit fee and on reasonable terms and conditions and with reasonable exceptions the municipality requires. The fee may not exceed the actual cost to the municipality of the utility's use of the public way and of administering the permit program. A dispute as to whether fees, terms, conditions, or exceptions are reasonable shall be decided by the commission. The commission may require a utility to add the amount of any permit fee paid as a pro rata surcharge to its bills for service rendered at locations within the boundaries of any municipality that requires payment of a permit fee.

*Sec. 42.05.253. Public utility regulatory cost charge. [Repealed, Sec. 36 ch 2 FSSLA 1992].*

Repealed or Renumbered

**Sec. 42.05.254. Public utility regulatory cost charge.**

(a) A regulated public utility operating in the state shall pay to the commission an annual regulatory cost charge in an amount not to exceed the maximum percentage of adjusted gross

revenue that applies to the utility sector of which the utility is a part. The regulatory cost charges that the commission expects to collect from all regulated utilities may not exceed the sum of the following percentages of the total adjusted gross revenue of all regulated public utilities derived from operations in the state: (1) not more than .7 percent to fund the operations of the commission, and (2) not more than .17 percent to fund operations of the public advocacy function under AS 42.04.070 (c) and AS 44.23.020(e) within the Department of Law. An exempt utility shall pay the actual cost of services provided to it by the commission.

(b) The commission shall by regulation establish a method to determine annually the amount of the regulatory cost charge for a public utility. If the amount the commission expects to collect under (a) of this section and under AS 42.06.286 (a) exceeds the authorized budgets of the commission and the Department of Law public advocacy function under AS 42.04.070 (c) and AS 44.23.020 (e), the commission shall, by order, reduce the percentages determined under (h) of this section so that the total amount of the fees collected approximately equals the authorized budgets of the commission and the Department of Law public advocacy function under AS 42.04.070 (c) and AS 44.23.020 (e) for the fiscal year.

(c) In determining the amount of the regulatory cost charge imposed under (a) of this section,

(1) a utility selling utility services at wholesale shall modify its gross revenue by deducting payments it receives for wholesale sales;

(2) a local exchange telephone utility shall modify its gross revenue by deducting payments received from other carriers for settlements or access charges;

(3) an electric utility shall reduce its gross revenue by subtracting the cost of power; in this paragraph, "cost of power" means the costs of generation and purchased power reported to the commission.

(d) The commission shall calculate the total regulatory cost charges to be levied against all regulated electric utilities under this section. The commission shall allocate the total amount among the regulated electric utilities by using an equal charge per kilowatt hour sold at retail.

(e) The commission shall administer the charge imposed under this section. The Department of Revenue shall collect and enforce the charge imposed under this section. The Department of Administration shall identify the amount of the operating budgets of the commission and the Department of Law public advocacy function under AS 42.04.070(c) and AS 44.23.020 (e) that lapse into the general fund each year. The legislature may appropriate an amount equal to the lapsed amount to the commission and to the Department of Law public advocacy function under AS 42.04.070 (c) and AS 44.23.020 (e) for operating costs for the next fiscal year. If the legislature does so, the commission shall reduce the total regulatory cost charge collected for that fiscal year by a comparable amount.

(f) The commission shall allow a public utility to recover all payments made to the commission under this section. The commission may not require a public utility to file a rate case in order to be eligible to recover the regulatory cost charge.

(g) The commission may adopt regulations under AS 44.62 (Administrative Procedure Act) necessary to administer this section, including requirements and procedures for reporting information and making quarterly payments. The Department of Revenue may adopt regulations under AS 44.62 (Administrative Procedure Act) for investigating the accuracy of filed information, and for collecting required payments.

(h) The commission shall by regulation establish a method to determine annually the maximum percentage of adjusted gross revenue that will apply to each regulated public utility sector and the maximum percentage of gross revenue that will apply to the regulated pipeline carrier sector. Other than the cost of services provided to exempt utilities, the method established shall allocate the commission's costs, and the Department of Law's certified costs of its public advocacy function under AS 42.04.070 (c) and AS 44.23.020 (e), among the regulated public utility sectors and the regulated pipeline carrier sector based on the relative amount of the commission's annual costs and the Department of Law's certified costs that is attributable to regulating each sector. For purposes of this subsection, the Department of Law shall annually certify to the commission the costs of its public advocacy function under AS 42.04.070 (c) and AS 44.23.020 (e).

(i) In this section,

(1) "adjusted gross revenue" means the gross revenue of a utility as modified under (c) of this section, if appropriate.

(2) "exempt utility" means a public utility that is certificated by the commission under AS 42.05.221 - 42.05.281 but, in accordance with AS 42.05.711, is exempt from other regulatory requirements of this chapter;

(3) "gross revenue" means the total operating revenue from intrastate services, as shown in a utility's annual report required by the commission by regulation;

(4) "regulated utility" means a public utility that is certificated by the commission under AS 42.05.221 - 42.05.281 and that is subject to the other regulatory requirements of this chapter;

(5) "wholesale sales" means sales to another utility for resale under circumstances that make revenue from the resale subject to the regulatory cost charge imposed under this section.

*Sec. 42.05.260. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

Sec. 42.05.261. Discontinuance, suspension, or abandonment of certificated service.

(a) Except as otherwise provided in this section, a public utility may not discontinue or abandon a service for which a certificate has been issued by the commission unless upon the application of the public utility and if, after notice and opportunity for hearing, the commission finds that the continued service is not required by public convenience and necessity. Any interested person may file with the commission a protest or memorandum of opposition to or in support of discontinuance or abandonment. The commission may authorize temporary suspension of a service or of part of a service.

(b) Upon complaint or upon its own motion, the commission may reinvestigate a previously authorized discontinuance, abandonment, or suspension of a service of an operating public utility. If, after providing notice and an opportunity for a hearing, the commission finds that the public convenience and necessity require the service to be resumed, it may order the public utility to again provide the service.

*Sec. 42.05.270. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

Sec. 42.05.271. Modification, suspension, or revocation of certificates.

Upon complaint or upon its own motion the commission, after notice and opportunity for hearing and for good cause shown, may amend, modify, suspend, or revoke a certificate, in whole or in part. Good cause for amendment, modification, suspension, or revocation of a certificate includes

- (1) the requirements of public convenience and necessity;
- (2) misrepresentation of a material fact in obtaining the certificate;
- (3) unauthorized discontinuance or abandonment of all or part of a public utility's service;
- (4) wilful failure to comply with the provisions of this chapter or the regulations or orders of the commission; or
- (5) wilful failure to comply with a term, condition, or limitation of the certificate.

*Sec. 42.05.280. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

Sec. 42.05.281. Transfer of certificate.

A certificate may not be sold or leased, rented, transferred or inherited without the prior approval of the commission.

*Sec. 42.05.290. [Repealed, 5 ch 113 SLA 1970].*

**Sec. 42.05.421. Suspension of tariff filing.**

(a) When a tariff filing is made containing a new or revised rate, classification, rule, regulation, practice, or condition of service the commission may, either upon written complaint or upon its own motion, after reasonable notice, conduct a hearing to determine the reasonableness and propriety of the filing. Pending the hearing the commission may, by order stating the reasons for its action, suspend the operation of the tariff filing. For a tariff filing that does not change the utility's revenue requirement or rate design, the suspension may last for a period not longer than six months beyond the effective date established in the tariff filing unless the commission extends the period for good cause. For a tariff filing that changes the utility's revenue requirement or rate design, the suspension may last, unless the commission extends the period for good cause, for a period not longer than

(1) six months before an interim rate equal to the requested rate goes into effect and not longer than 12 months before a permanent rate goes into effect if the annual gross revenues of the utility making the filing are more than \$3,000,000; and

(2) 150 days before an interim rate equal to the requested new rate goes into effect and not longer than one year before a permanent rate goes into effect if the annual gross revenues of the utility making the filing are \$3,000,000 or less.

(b) An order suspending a tariff filing may be vacated if, after investigation, the commission finds that it is in all respects proper. Otherwise the commission shall hold a hearing on the suspended filing and issue its order, before the end of the suspension period, granting, denying or modifying the suspended tariff in whole or in part.

(c) In the case of a proposed increased rate, the commission may by order require the interested public utility or utilities to place in escrow in a financial institution approved by the commission and keep accurate account of all amounts received by reason of the increase, specifying by whom and in whose behalf the amounts are paid. Upon completion of the hearing and decision the commission may by order require the public utility to refund to the persons in whose behalf the amounts were paid, that portion of the increased rates which was found to be unreasonable or unlawful. Funds may not be released from escrow without the commission's prior written consent and the escrow agent shall be so instructed by the utility, in writing, with a copy to the commission. The utility may, at its expense, substitute a bond in lieu of the escrow requirement.

(d) One who initiates a change in existing tariffs shall bear the burden to prove the reasonableness of the change.

*Sec. 42.05.430. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

Sec. 42.05.431. Power of commission to fix rates.

(a) When the commission, after an investigation and hearing, finds that a rate demanded, observed, charged, or collected by a public utility for a service subject to the jurisdiction of the commission, or that a classification, rule, regulation, practice, or contract affecting the rate, is unjust, unreasonable, unduly discriminatory or preferential, the commission shall determine a just and reasonable rate, classification, rule, regulation, practice, or contract to be observed or allowed and shall establish it by order. A municipality may covenant with bond purchasers regarding rates of a municipally owned utility, and the covenant is valid and enforceable and is considered to be a contract with the holders from time to time of the bonds. The financial covenants contained in mortgages and other debt instruments of cooperative utilities organized under AS 10.25 are also valid and enforceable, and rates set by the commission must be adequate to meet those covenants. However, a cooperative utility that is negotiating to enter a mortgage or other debt instrument that provides for a times-interest-earned ratio (TIER) greater than the ratio the commission most recently approved for that cooperative shall submit the mortgage or debt instrument to the commission before the instrument takes effect. The commission may disapprove the instrument within 60 days after its submission. If the commission has not acted within 60 days, the instrument is considered to be approved.

(b) A wholesale power agreement between public utilities is subject to advance approval of the commission. After a wholesale power agreement is in effect, the commission may not invalidate any purchase or sale obligation under the agreement. However, if the commission finds that rates set in accordance with the agreement are not just and reasonable, the commission may order the parties to negotiate an amendment to the agreement and if the parties fail to agree, to use the dispute resolution procedures contained in the contract.

(c) Notwithstanding (b) of this section,

(1) a wholesale agreement for the sale of power from a project licensed by the Federal Energy Regulatory Commission on or before January 1, 1987, and related contracts for the wheeling, storage, regeneration, or wholesale repurchase of power purchased under the agreement, entered into between the Alaska Energy Authority and one or more other public utilities or among the utilities after October 31, 1987, and before January 1, 1988, and amendments to the wholesale agreement or related contract, and the wholesale agreement or related contract assigned by the Alaska Energy Authority to a joint action agency formed under AS 42.45.310 that purchases the project from the Alaska Energy Authority, are not subject to review or approval by the commission until all long-term debt incurred for the project is retired, or, for a wholesale agreement or related contract assigned to a joint action agency formed under AS 42.45.310, until all long-term debt incurred to pay the purchase price to the Alaska Energy Authority is retired; and

(2) a wholesale agreement or related contract described in (1) of this subsection may contain a covenant for the public utility to establish, charge, and collect rates sufficient to meet its obligations under the contract; the rate covenant is valid and enforceable.

(d) Meetings between the Alaska Energy Authority and public utilities concerning a wholesale agreement for the sale of power or other matter exempted from review of the commission under (c) of this section must comply with AS 44.62.310.

(e) Validated costs incurred by a utility in connection with the related contracts described in (c)(1) of this section must be allowed in the rates charged by the utility. In this subsection, "validated costs" are the actual costs that a utility uses, under the formula set out in related contracts described in (c) of this section, to establish rates, charges for services and rights, and the payment of charges for services and rights. This subsection does not grant the commission jurisdiction to alter or amend the formula set out in those related contracts.

(f) In the establishment of rates of a utility furnishing solid waste material collection and disposal service, the commission shall permit recovery of reasonable, net capital and operating costs relating to solid waste recovery and recycling services after considering the utility's recovery of revenue associated with the service.

(g) In the establishment of rates under this chapter, the commission shall promote cost-effective solid waste recovery and recycling services.

(h) When setting or reviewing rates for a public utility that sends or receives power over the power transmission interties between Fairbanks and Healy or between Anchorage and the Kenai Peninsula, the commission shall consider those costs that have not been directly assigned to other individual generating utilities by the utility responsible for the construction of the intertie to have been incurred for the system existing on August 11, 1993.

*Sec. 42.05.440. [Repealed, Sec. 5 ch 113 SLA 1970].*

Repealed or Renumbered

## Miscellaneous Provisions

### Sec. 42.05.691. Utility classes.

The commission may by regulation provide for the classification of public utilities based upon differences in annual revenue, assets, nature of ownership, and other appropriate distinctions and as between these classifications, by regulation, provide for different reporting, accounting, and other regulatory requirements.

### Sec. 42.05.711. Exemptions.

(a) The provisions of this chapter do not apply to a person who furnishes water, gas or petroleum or petroleum products by tank, wagon, or similar conveyance, unless the person is thereby supplying water, gas, petroleum or petroleum products to a public utility in which the person has an "affiliated interest".

(b) Except as otherwise provided in this subsection and in (o) of this section, public utilities owned and operated by a political subdivision of the state, or electric operating entities established as the instrumentality of two or more public utilities owned and operated by political subdivisions of the state, are exempt from this chapter, other than AS 42.05.221 - 42.05.281 and 42.05.385. However,

(1) the governing body of a political subdivision may elect to be subject to this chapter; and

(2) a utility or electric operating entity that is owned and operated by a political subdivision and that directly competes with another utility or electric operating entity is subject to this chapter and any other utility or electric operating entity owned and operated by the political subdivision is also subject to this chapter; this paragraph does not apply to a utility or electric operating entity owned and operated by a political subdivision that competes with a telecommunications utility.

(c) The ownership in whole or part, of the corporate stock of a public utility does not make the owner a public utility.

(d) The commission may exempt a utility, a class of utilities, or a utility service from all or a portion of this chapter if the commission finds that the exemption is in the public interest.

(e) Notwithstanding any other provisions of this chapter, any electric or telephone utility that does not gross \$50,000 annually is exempt from regulation under this chapter unless the subscribers petition the commission for regulation under AS 42.05.712 (h).

(f) Notwithstanding any other provisions of this chapter, an electric or telephone utility that does not gross \$500,000 annually may elect to be exempt from the provisions of this chapter other than AS 42.05.221 - 42.05.281 under the procedure described in AS 42.05.712.

(g) A utility, other than a telephone or electric utility, that does not gross \$150,000 annually may elect to be exempt from the provisions of this chapter other than AS 42.05.221 - 42.05.281 under the procedure described in AS 42.05.712.

(h) A cooperative organized under AS 10.25 may elect to be exempt from the provisions of this chapter, other than AS 42.05.221 - 42.05.281, under the procedure described in AS 42.05.712.

(i) A utility that furnishes collection and disposal service of garbage, refuse, trash, or other waste material and has annual gross revenues of \$300,000 or less is exempt from the provisions of this chapter, other than the certification provisions of AS 42.05.221 - 42.05.281, unless the subscribers petition the commission for regulation under AS 42.05.712 (h). Notwithstanding AS 42.05.712 (b) and (g), if subscribers representing 25 percent of the gross revenue of the utility petition the commission for regulation, the utility is subject to the provisions of this chapter.

(j) The provisions of this chapter do not apply to sales, exchanges, or gifts of energy to an electric utility certificated under this chapter when the energy which is the subject of the sale, exchange, or gift is waste heat, electricity, or other energy which is surplus or the by-product of an industrial process. In an area in which no electric utility is certificated for service, energy provided by sale, exchange, or gift may be provided to any utility which is certificated for service to that area. A contract for the sale, exchange, or gift of energy exempt under this subsection does not make the supplier a public utility and does not transfer the responsibility to provide utility services from a certificated utility to any other person.

(k) A utility that furnishes cable television service is exempt from the provisions of this chapter other than AS 42.05.221 - 42.05.281 unless the subscribers petition the commission for regulation under the procedure described in AS 42.05.712.

(l) A person, utility, joint action agency established under AS 42.45.310, or cooperative that is exempt from regulation under (a), (d) - (k), or (o) of this section is not subject to regulation by a municipality under AS 29.35.060 and 29.35.070.

(m) The collection and disposal, under AS 29.35.050 (c), by a municipality of waste material deposited at an intermediate transfer site is exempt from this chapter.

(n) Except as provided by AS 42.06.370 (c), the provisions of this chapter do not apply to a person who owns or operates a natural gas pipeline as a North Slope natural gas pipeline carrier, as that term is defined in AS 42.06.630.

(o) A joint action agency established under AS 42.45.310 is exempt from regulation under this chapter, including the requirement to obtain a certificate of public convenience and necessity under AS 42.05.221, for the operation of, sale of power from, and other activities related to the power project the joint action agency purchases from the Alaska Energy Authority until the wholesale agreement and any related contract assigned by the authority becomes subject to review or approval by the commission under AS 42.05.431. The exemption provided by this subsection extends to repairs and improvements to the power project the joint action agency

purchases from the authority but does not extend to any other power project or other activity of the joint action agency.

(p) A regional solid waste management authority established under AS 29.35.800 - 29.35.925 is exempt from regulation under this chapter, except that a solid waste management authority is subject to this chapter if it directly competes with a utility subject to this chapter.

Article 10. GENERAL PROVISIONS

**Sec. 42.05.990. Definitions.**

In this chapter

(1) "affiliated interest" includes:

(A) a person owning or holding directly or indirectly five percent or more of the voting securities of a public utility engaged in intrastate business in this state;

(B) a person, other than those specified in (A) of this paragraph, in a chain of successive ownership of five percent or more of voting securities, the chain beginning with the holder of the voting securities of such public utility;

(C) a corporation five percent or more of whose voting securities are owned by a person owning five percent or more of the voting securities of the public utility or by a person in such a chain of successive ownership of five percent or more of the voting securities;

(D) a corporation five percent or more of whose voting securities are owned or held by a public utility;

(E) a person with whom the public utility has a management or service contract;

(F) a person who is an officer or director of such a public utility or of a corporation in a chain of successive ownership of five percent or more of voting securities;

(G) a corporation which has one or more officers or directors in common with a public utility;

(H) a person or corporation who or which the commission determines as a matter of fact, after investigation and hearing, actually is exercising such substantial influence over the policies and actions of a utility in conjunction with one or more other corporations or persons with whom they are related by ownership or blood, or by action in concert, that together they are affiliated with the utility within the meaning of this section even though none of them alone is so affiliated; or

(I) a person or corporation who or which the commission determines as a matter of fact after investigation and hearing actually is exercising substantial influence over the policies and actions of a utility even though such influence is not based upon stockholdings, stockholders, officers or directors to the extent specified in this section;

(2) "commission" means the Regulatory Commission of Alaska;

(3) "public" or "general public" means

(A) a group of 10 or more customers that purchase the service or commodity furnished by a public utility;

(B) one or more customers that purchase electrical service for use within an area that is certificated to and presently or formerly served by an electric utility if the total annual compensation that the electrical utility receives for sales of electricity exceeds \$50,000; and

(C) a utility purchasing the product or service or paying for the transmission of electric energy, natural or manufactured gas, or petroleum products that are re-sold to a person or group included in (A) or (B) of this paragraph or that are used to produce the service or commodity sold to the public by the utility;

(4) "public utility" or "utility" includes every corporation whether public, cooperative, or otherwise, company, individual, or association of individuals, their lessees, trustees, or receivers appointed by a court, that owns, operates, manages, or controls any plant, pipeline, or system for

(A) furnishing, by generation, transmission, or distribution, electrical service to the public for compensation;

(B) furnishing telecommunications service to the public for compensation;

(C) furnishing water, steam, or sewer service to the public for compensation;

(D) furnishing by transmission or distribution of natural or manufactured gas to the public for compensation;

(E) furnishing for distribution or by distribution petroleum or petroleum products to the public for compensation when the consumer has no alternative in the choice of supplier of a comparable product and service at an equal or lesser price;

(F) furnishing collection and disposal service of garbage, refuse, trash, or other waste material to the public for compensation;

(5) "rate" includes each rate, toll, fare, rental, charge, or other form of compensation demanded, observed, charged, or collected by a public utility for its services;

(6) "service" means, unless the context indicates otherwise, every commodity, product, use, facility, convenience, or other form of service that is offered for and provided by a public utility for the convenience and necessity of the public;

(7) "tariff" means a rate, charge, toll, rule, or regulation of a utility relating to services furnished by the utility to the general public for compensation and every map, page, adoption notice, instrument, or other document filed with the commission setting out the terms and conditions under which utility services are offered to the public and instruments of concurrence and all other documents and data setting out the terms of a utility's business relations with another utility insofar as they affect the general public either directly or indirectly;

(8) "telecommunications" means the transmission and reception of messages, impressions, pictures, and signals by means of electricity, electromagnetic waves, and any other kind of energy, force variations, or impulses whether conveyed by cable, wire, radiated through space, or transmitted through other media within a specified area or between designated points.



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### What is a Qualifying Facility?

(Note: Some of the links on this page are to external sites and you will be leaving FERC's website)

The Public Utility Regulatory Policies Act of 1978 (PURPA) was implemented to encourage, among other things,

1. the conservation of electric energy,
2. increased efficiency in the use of facilities and resources by electric utilities,
3. equitable retail rates for electric consumers,
4. expeditious development of hydroelectric potential at existing small dams, and
5. conservation of natural gas while ensuring that rates to natural gas consumers are equitable.

One of the ways PURPA set out to accomplish its goals was through the establishment of a new class of generating facilities which would receive special rate and regulatory treatment. Generating facilities in this group are known as qualifying facilities (QFs), and fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities.

A **small power production facility** is a generating facility of 80 MW or less whose primary energy source is renewable (hydro, wind or solar), biomass, waste, or geothermal resources. There are some limited exceptions to the 80 MW size limit that apply to certain facilities certified prior to 1995 and designated under section 3(17)(E) of the Federal Power Act (FPA) (16 U.S.C. § 796(17)(E)) which have no size limitation. In order to be considered a qualifying small power production facility, a facility must meet all of the requirements of 18 C.F.R. §§ 292.203(a), 292.203(c) and 292.204 for size and fuel use, and be certified as a QF pursuant to 18 C.F.R. § 292.207.

A **cogeneration facility** is a generating facility that sequentially produces electricity and another form of useful thermal energy (such as heat or steam) in a way that is more efficient than the separate production of both forms of energy. For example, in addition to the production of electricity, large cogeneration facilities might provide steam for industrial uses in facilities such as paper mills, refineries, or factories, or for HVAC applications in commercial or residential buildings. Smaller cogeneration facilities might provide hot water for domestic heating or other useful applications. In order to be considered a qualifying cogeneration facility, a facility must meet all of the requirements of 18 C.F.R. §§ 292.203(b) and 292.205 for operation, efficiency and use of energy output, and be certified as a QF pursuant to 18 C.F.R. § 292.207. There is no size limitation for qualifying cogeneration facilities.

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- » 18 C.F.R. § 131.80
- » 18 C.F.R. Part 292
- » Filing Fees
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### What Are the Benefits of QF Status?

QFs may enjoy certain benefits under Federal, State and local laws. The benefits that are conferred upon QFs by Federal law generally fall into three categories: (1) the right to sell energy or capacity to a utility, (2) the right to purchase certain services from utilities, and (3) relief from certain regulatory burdens.

#### Right to Sell QF Energy or Capacity to a Utility

QFs have the right to sell energy and capacity to a utility (see 18 C.F.R. § 304 [ϕ](#)), provided the purchasing utility has not been relieved from its QF purchase obligation (see 18 C.F.R. § 309-311 [ϕ](#)). With limited exceptions, QFs generally have the option of selling to a utility either at the utility's avoided cost or at a negotiated rate. Avoided cost is the incremental cost to an electric utility of electric energy or capacity which, but for the purchase from the QF, such utility would generate itself or purchase from another source (see 18 C.F.R. § 292.101(b)(6) [ϕ](#)). QFs also generally have the option to sell energy either "as-available" (i.e., as the QF determines such energy to be available for such purchases) or as part of a legally enforceable obligation for delivery of energy or capacity over a specified term.

#### Right to Purchase Certain Services from Utilities

QFs have the right to purchase supplementary power, back-up power, maintenance power, and interruptible power at rates which are just and reasonable, based on accurate data and consistent system-wide costing principles, and that apply to the utility's other customers with similar load or cost-related characteristics (see 18 C.F.R. § 292.305 [ϕ](#)), provided the selling utility has not been relieved from its QF sales obligation (see 18 C.F.R. § 312 [ϕ](#) - 313 [ϕ](#)). QFs also have the right to interconnect with a utility by paying a nondiscriminatory interconnection fee approved by the State regulatory authority or a nonregulated electric utility (see 18 C.F.R. § 292.306 [ϕ](#)).

#### Relief from Regulatory Burdens

The following categories of QFs are exempt from the Public Utility Holding Company Act of 2005 (PUHCA) (see 18 C.F.R. § 292.602 [ϕ](#)):

- Cogeneration facilities of any size;
- Small power production facilities 30 MW or smaller;
- Geothermal and biomass small power production facilities of any size; and
- Small power production facilities of any size that are designated as "eligible" under section 3(17)(E) of the Federal Power Act (FPA).

The following categories of QFs are exempt from State laws and regulations respecting the rates and financial and organizational aspects of utilities (see 18 C.F.R. § 292.602 [ϕ](#)):

- Cogeneration facilities of any size;
- Small power production facilities 30 MW or smaller;
- Geothermal and biomass small power production facilities of any size; and
- Small power production facilities of any size that are designated as "eligible" under section 3(17)(E) of the FPA.

The following categories of QFs are largely exempt from most sections (not including sections 205, 206 and certain other sections) of the FPA (see 18 C.F.R. § 292.601 [ϕ](#)):

- Cogeneration facilities of any size;
- Small power production facilities 30 MW or smaller;
- Geothermal small power production facilities of any size; and
- Small power production facilities of any size that are designated as "eligible" under section 3(17)(E) of the FPA.

Energy and capacity sales made by the following categories of QFs are exempt from scrutiny under sections 205 and 206 of the FPA (see 18 C.F.R. § 292.601 [ϕ](#)):

- QFs 20 MW or smaller;

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Related Topics

- 18 C.F.R. § 131.80 [ϕ](#)
- 18 C.F.R. Part 292 [ϕ](#)
- Filing Fees
- Cogeneration facilities order on rehearing Order No. 671-A [PDF](#)
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- QFs making sales pursuant to a contract executed on or before March 17, 2006; and
- QFs making sales pursuant to a state regulatory authority's implementation of section 210 of PURPA.

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**How to Obtain QF Status for Your Facility**

An owner or operator of a generating facility may obtain QF status by either submitting a self-certification or applying for and obtaining a Commission certification of QF status. The choice of whether to certify a facility through a self-certification or Commission certification is up to the applicant. In some instances, negotiations with a lender or utility purchaser may proceed more smoothly if the facility has been certified by the Commission.

A completed Form No. 556 must be submitted with each self-certification or application for Commission certification of QF status. Most types of QF filings also have an associated notice requirement; see the Commission's QF Notice Requirements website for more information.

There are two methods of making QF filings:

- [eFiling](#)
- [By Mail](#)

All QF self-certifications and applications for Commission certifications may be filed electronically, and applicants are strongly encouraged to use the electronic filing process. By filing electronically, you will reduce your filing burden, save paper resources, save postage or courier charges, help keep Commission expenses to a minimum, and receive a much faster confirmation (via an email containing the docket number assigned to your facility) that the Commission has received your filing.

When prompted, select one of the following filing types, as appropriate, from the Electric menu:

- (Fee) Application for Commission Cert. as Cogeneration QF
- (Fee) Application for Commission Cert. as Small Power QF
- Self-Certification Notice (QF, EG, FC)
- Self-Certification of Qualifying Facility (QF)
- Supplemental Information or Request (use this selection if you are supplementing or correcting a filing, whether on your own initiative, or at the request of Commission staff)

If you are required to pay a fee, you will be prompted to submit your fee electronically during the electronic filing process. You can pay via credit card or electronic debit from a bank account. If you are eFiling an application which requires you to submit a draft *Federal Register* notice (see Notice Requirements page for information), you must upload your draft notice in a word processing format (DOC, RTF, WPD, etc.) during the eFiling process.

To file a hardcopy of your self-certification or application for Commission certification, make sure the filing is completed and signed, and send the filing (including original and 14 copies of the Form No. 556 and any required attachments) and a check for the filing fee (if applicable) to the Secretary at the address listed in the Contact Us - Official Communication section.

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**Self-Certification**

A self-certification of QF status under 18 C.F.R. § 292.207(a) must include the following:

- A completed Form No. 556.
- If the self-certification is for a "new cogeneration facility" (as defined below), then the public will be given notice of the filing through an announcement in the *Federal Register*. Thus, self-certifications of "new cogeneration facilities" must be accompanied by a draft notice suitable for publication in the *Federal Register*. See the Commission's [QF Notice Requirements](#) page for more information. A "new cogeneration facility" is a cogeneration facility that was either not certified as a QF on or before August 8, 2005, or that had not filed a notice of self-certification, self-recertification or an application for Commission certification or Commission recertification as a qualifying cogeneration facility on or before February 1, 2006.

There is no fee for filing a self-certification.

Applicants will be notified of their docket number either by email (if their application is eFiled) or by U.S. mail (if their application is filed in hardcopy format). Keep this number for future reference. You will receive no other document from the Commission for self-certifications.

Applicants for self-certification who have not yet received their docket number from the Secretary can locate their filed documents and find their docket number by performing a [New Dockets Search](#) in eLibrary.

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**Application for Commission Certification**

An application for Commission certification of QF status under 18 C.F.R. § 292.207(b)  $\varnothing$  must include the following:

- A completed Form No. 556.
- For all applications for Commission certification, the public is given notice through an announcement in the *Federal Register* of the filing of applications for Commission certification. Thus, applications for Commission certification must be accompanied by a draft notice suitable for publication in the *Federal Register*. See the Commission's QF [Notice Requirements](#) page for more information.
- A check for the filing fee made payable to the Treasurer of the United States. Please visit our [Filing Fees](#) page for the most current filing fee. A filing date will not be assigned to an application unless it is accompanied by the proper fee.

After submitting an application, applicants can locate documents related to their application and find their docket number by performing a New Dockets Search in eLibrary.

Within 90 days of the filing of an application, the Commission will either inform the applicant that the filing is deficient, issue an order granting or denying the application, or act to postpone the date for issuing an order. Under 18 C.F.R., 292.207(b)(3)  $\varnothing$ , if the Commission has not acted upon the application within 90 days of the filing date, it shall be deemed granted.

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## e-CFR Data is current as of March 1, 2010

### **Title 18: Conservation of Power and Water Resources**

#### **PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION**

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### **Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978**

**Authority:** Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.* Federal Power Act, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267.

**Source:** Order 69, 45 FR 12234, Feb. 25, 1980, unless otherwise noted.

#### **§ 292.301 Scope.**

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

#### **§ 292.302 Availability of electric utility system cost data.**

(a) *Applicability.* (1) Except as provided in paragraph (a)(2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale exceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until June 30, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) *Special rule for small electric utilities.* (1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) *Substitution of alternative method.* (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any non-regulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) *State Review.* (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

[45 FR 12234, Feb. 25, 1980; 45 FR 24126, Apr. 9, 1980]

### **§ 292.303 Electric utility obligations under this subpart.**

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with §292.304, unless exempted by §292.309 and §292.310, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with §292.305, unless exempted by §292.312, energy and capacity requested by the qualifying facility.

(c) *Obligation to interconnect.* (1) Subject to paragraph (c)(2) of this section, any electric utility shall make such interconnection costs with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection shall be determined in accordance with §292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to §292.304(e)(4) and shall not include any charges for transmission.

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with §292.308.

[Order 688, 71 FR 64372, Nov. 1, 2006; 71 FR 75662, Dec. 18, 2006]

### **§ 292.304 Rates for purchases.**

(a) *Rates for purchases.* (1) Rates for purchases shall:

- (i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and
- (ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b)(3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section

(3) A rate for purchases (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b)(2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

- (i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to §292.302(b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) *Periods during which purchases not required.* (1) Any electric utility which gives notice pursuant to paragraph (f)(2) of this section will not be required to purchase electric energy or capacity during any period during which, due to

operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f)(1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery of energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f)(2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f)(1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

### **§ 292.305 Rates for sales.**

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional services to be provided to qualifying facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b)(1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

**§ 292.306 Interconnection costs.**

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

**§ 292.307 System emergencies.**

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

**§ 292.308 Standards for operating reliability.**

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recommended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

**§ 292.309 Termination of obligation to purchase from qualifying facilities.**

(a) After August 8, 2005, an electric utility shall not be required, under this part, to enter into a new contract or obligation to purchase electric energy from a qualifying cogeneration facility or a qualifying small power production facility if the Commission finds that the qualifying cogeneration facility or qualifying small power facility production has nondiscriminatory access to:

(1)(i) Independently administered, auction-based day ahead and real time wholesale markets for the sale of electric energy; and

(ii) Wholesale markets for long-term sales of capacity and electric energy; or

(2)(i) Transmission and interconnection services that are provided by a Commission-approved regional transmission entity and administered pursuant to an open access transmission tariff that affords nondiscriminatory treatment to all customers; and

(ii) Competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In determining whether a meaningful opportunity to sell exists, the Commission shall consider, among other factors, evidence of transactions within the relevant market; or

(3) Wholesale markets for the sale of capacity and electric energy that are, at a minimum, of comparable competitive quality as markets described in paragraphs (a)(1) and (a)(2) of this section.

(b) For purposes of §292.309(a), a renewal of a contract that expires by its own terms is a "new contract or obligation" without a continuing obligation to purchase under an expired contract.

(c) For purposes of §292.309(a)(1), (2) and (3), with the exception of paragraph (d) of this section, there is a rebuttable presumption that a qualifying facility has nondiscriminatory access to the market if it is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, and Commission-approved interconnection rules. If the Commission determines that a market meets the criteria of §292.309(a)(1), (2) or (3), and if a qualifying facility in the relevant market is eligible for service under a Commission-approved open access transmission tariff or Commission-filed reciprocity tariff, a qualifying facility may seek to rebut the presumption of access to the market by demonstrating, *inter alia*, that it does not have access to the market because of operational characteristics or transmission constraints.

(d)(1) For purposes of §292.309(a)(1), (2), and (3), there is a rebuttable presumption that a qualifying facility with a capacity at or below 20 megawatts does not have nondiscriminatory access to the market.

(2) For purposes of implementing paragraph (d)(1) of this section, the Commission will not be bound by the one-mile standard set forth in §292.204(a)(2).

(e) Midwest Independent Transmission System Operator (Midwest ISO), PJM Interconnection, L.L.C. (PJM), ISO New England, Inc. (ISO-NE), and New York Independent System Operator (NYISO) qualify as markets described in §292.309(a)(1)(i) and (ii), and there is a rebuttable presumption that qualifying facilities with a capacity greater than 20 megawatts have nondiscriminatory access to those markets through Commission-approved open access transmission tariffs and interconnection rules, and that electric utilities that are members of such regional transmission organizations or independent system operators (RTO/ISOs) should be relieved of the obligation to purchase electric energy from the qualifying facilities. A qualifying facility may seek to rebut this presumption by demonstrating, *inter alia*, that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or

(2) The qualifying facility lacks access to markets due to transmission constraints. The qualifying facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.

(f) The Electric Reliability Council of Texas (ERCOT) qualifies as a market described in §292.309(a)(3), and there is a rebuttable presumption that qualifying facilities with a capacity greater than 20 megawatts have nondiscriminatory access to that market through Public Utility Commission of Texas (PUCT) approved open access protocols, and that electric utilities that operate within ERCOT should be relieved of the obligation to purchase electric energy from the qualifying facilities. A qualifying facility may seek to rebut this presumption by demonstrating, *inter alia*, that:

(1) The qualifying facility has certain operational characteristics that effectively prevent the qualifying facility's participation in a market; or

(2) The qualifying facility lacks access to markets due to transmission constraints. The qualifying facility may show that it is located in an area where persistent transmission constraints in effect cause the qualifying facility not to have access to markets outside a persistently congested area to sell the qualifying facility output or capacity.

(g) The California Independent System Operator and Southwest Power Pool, Inc. satisfy the criteria of §292.309(a)(2)(i).

(h) No electric utility shall be required, under this part, to enter into a new contract or obligation to purchase from or sell electric energy to a facility that is not an existing qualifying cogeneration facility unless the facility meets the criteria for new qualifying cogeneration facilities established by the Commission in §292.205.

(i) For purposes of §292.309(h), an "existing qualifying cogeneration facility" is a facility that:

(1) Was a qualifying cogeneration facility on or before August 8, 2005; or

(2) Had filed with the Commission a notice of self-certification or self-recertification, or an application for Commission certification, under §292.207 prior to February 2, 2006.

(j) For purposes of §292.309(h), a "new qualifying cogeneration facility" is a facility that satisfies the criteria for qualifying cogeneration facilities pursuant to §292.205.

[Order 688, 71 FR 64372, Nov. 1, 2006; 71 FR 75662, Dec. 18, 2006]

**§ 292.310 Procedures for utilities requesting termination of obligation to purchase from qualifying facilities.**

(a) An electric utility may file an application with the Commission for relief from the mandatory purchase requirement under §292.303(a) pursuant to this section on a service territory-wide basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in §292.309(a)(1), (2) or (3) have been met. After notice, including sufficient notice to potentially affected qualifying cogeneration facilities and qualifying small power production facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in §292.309(a)(1), (2) or (3) have been met.

(b) Sufficient notice shall mean that an electric utility must identify with names and addresses all potentially affected qualifying facilities in an application filed pursuant to paragraph (a).

(c) An electric utility must submit with its application for each potentially affected qualifying facility: The docket number assigned if the qualifying facility filed for self-certification or an application for Commission certification of qualifying facility status; the net capacity of the qualifying facility; the location of the qualifying facility depicted by state and county, and the name and location of the substation where the qualifying facility is interconnected; the interconnection status of each potentially affected qualifying facility including whether the qualifying facility is interconnected as an energy or a network resource; and the expiration date of the energy and/or capacity agreement between the applicant utility and each potentially affected qualifying facility. All potentially affected qualifying facilities shall include:

(1) Those qualifying facilities that have existing power purchase contracts with the applicant;

(2) Other qualifying facilities that sell their output to the applicant or that have pending self-certification or Commission certification with the Commission for qualifying facility status whereby the applicant will be the purchaser of the qualifying facility's output;

(3) Any developer of generating facilities with whom the applicant has agreed to enter into power purchase contracts, as of the date of the application filed pursuant to this section, or are in discussion, as of the date of the application filed pursuant to this section, with regard to power purchase contracts;

(4) The developers of facilities that have pending state avoided cost proceedings, as of the date of the application filed pursuant to this section; and

(5) Any other qualifying facilities that the applicant reasonably believes to be affected by its application filed pursuant to paragraph (a) of this section.

(d) The following information must be filed with an application:

(1) Identify whether applicant seeks a finding under the provisions of §292.309(a)(1), (2), or (3).

(2) A narrative setting forth the factual basis upon which relief is requested and describing why the conditions set forth in §292.309(a)(1), (2), or (3) have been met. Applicant should also state in its application whether it is relying on the findings or rebuttable presumptions contained in §292.309(e), (f) or (g). To the extent applicant seeks relief from the purchase obligation with respect to a qualifying facility 20 megawatts or smaller, and thus seeks to rebut the presumption in §292.309(d), applicant must also set forth, and submit evidence of, the factual basis supporting its contention that the qualifying facility has nondiscriminatory access to the wholesale markets which are the basis for the applicant's filing.

(3) Transmission Studies and related information, including:

(i) The applicant's long-term transmission plan, conducted by applicant, or the RTO, ISO or other relevant entity;

(ii) Transmission constraints by path, element or other level of comparable detail that have occurred and/or are known and expected to occur, and any proposed mitigation including transmission construction plans;

(iii) Levels of congestion, if available;

(iv) Relevant system impact studies for the generation interconnections, already completed;

(v) Other information pertinent to showing whether transfer capability is available; and

(vi) The appropriate link to applicant's OASIS, if any, from which a qualifying facility may obtain applicant's available transfer capability (ATC) information.

(4) Describe the process, procedures and practices that qualifying facilities interconnected to the applicant's system must follow to arrange for the transmission service to transfer power to purchasers other than the applicant. This description must include the process, procedures and practices of all distribution, transmission and regional transmission facilities necessary for qualifying facility access to the market.

(5) If qualifying facilities will be required to execute new interconnection agreements, or renegotiate existing agreements so that they can effectuate wholesale sales to third-party purchasers, explain the requirements, charges and the process to be followed. Also, explain any differences in these requirements as they apply to qualifying facilities compared to other generators, or to applicant-owned generation.

(6) Applicants seeking a Commission finding pursuant to §292.309(a)(2) or (3), except those applicants located in ERCOT, also must provide evidence of competitive wholesale markets that provide a meaningful opportunity to sell capacity, including long-term and short-term sales, and electric energy, including long-term, short-term and real-time sales, to buyers other than the utility to which the qualifying facility is interconnected. In demonstrating that a meaningful opportunity to sell exists, provide evidence of transactions within the relevant market. Applicants must include a list of known or potential purchasers, e.g., jurisdictional and non-jurisdictional utilities as well as retail energy service providers.

(7) Signature of authorized individual evidencing the accuracy and authenticity of information provided by applicant.

(8) Person(s) to whom communications regarding the filed information may be addressed, including name, title, telephone number, and mailing address.

[Order 688, 71 FR 64372, Nov. 1, 2006, as amended by Order 688-A, 72 FR 35892, June 29, 2007]

### **§ 292.311 Reinstatement of obligation to purchase.**

At any time after the Commission makes a finding under §§292.309 and 292.310 relieving an electric utility of its obligation to purchase electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's

obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in §292.309(a), (b) or (c) are no longer met. After notice, including sufficient notice to potentially affected electric utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to purchase electric energy under this section if the Commission finds that the conditions set forth in §292.309(a), (b), or (c) which relieved the obligation to purchase, are no longer met.

[Order 688, 71 FR 64372, Nov. 1, 2006]

#### **§ 292.312 Termination of obligation to sell to qualifying facilities.**

(a) Any electric utility may file an application with the Commission for relief from the mandatory obligation to sell under this section on a service territory-wide basis or a single qualifying facility basis. Such application shall set forth the factual basis upon which relief is requested and describe why the conditions set forth in paragraphs (b)(1) and (b)(2) of this section have been met. After notice, including sufficient notice to potentially affected qualifying facilities, and an opportunity for comment, the Commission shall make a final determination within 90 days of such application regarding whether the conditions set forth in paragraphs (b)(1) and (b)(2) of this section have been met.

(b) After August 8, 2005, an electric utility shall not be required to enter into a new contract or obligation to sell electric energy to a qualifying small power production facility, an existing qualifying cogeneration facility, or a new qualifying cogeneration facility if the Commission has found that;

(1) Competing retail electric suppliers are willing and able to sell and deliver electric energy to the qualifying cogeneration facility or qualifying small power production facility; and

(2) The electric utility is not required by State law to sell electric energy in its service territory.

[Order 688, 71 FR 64372, Nov. 1, 2006; 71 FR 75662, Dec. 18, 2006]

#### **§ 292.313 Reinstatement of obligation to sell.**

At any time after the Commission makes a finding under §292.312 relieving an electric utility of its obligation to sell electric energy, a qualifying cogeneration facility, a qualifying small power production facility, a State agency, or any other affected person may apply to the Commission for an order reinstating the electric utility's obligation to purchase electric energy under this section. Such application shall set forth the factual basis upon which the application is based and describe why the conditions set forth in Paragraph (b)(1) and (b)(2) of this section are no longer met. After notice, including sufficient notice to potentially affected utilities, and opportunity for comment, the Commission shall issue an order within 90 days of such application reinstating the electric utility's obligation to sell electric energy under this section if the Commission finds that the conditions set forth in paragraphs (b)(1) and (b)(2) of this section are no longer met.

[Order 688, 71 FR 64372, Nov. 1, 2006]

#### **§ 292.314 Existing rights and remedies.**

Nothing in this section affects the rights or remedies of any party under any contract or obligation, in effect or pending approval before the appropriate State regulatory authority or non-regulated electric utility on or before August 8, 2005, to purchase electric energy or capacity from or to sell electric energy or capacity to a qualifying cogeneration facility or qualifying small power production facility under this Act (including the right to recover costs of purchasing electric energy or capacity).

[Order 688, 71 FR 64372, Nov. 1, 2006]

**e-CFR Data is current as of March 1, 2010**

## **Title 18: Conservation of Power and Water Resources**

### **PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION**

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#### **Subpart D—Implementation**

**Authority:** Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601 *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791 *et seq.*, Federal Power Act, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101 *et seq.*, E.O. 12009, 42 FR 46267.

**Source:** Order 69, 45 FR 12236, Feb. 25, 1980, unless otherwise noted.

#### **§ 292.401 Implementation of certain reporting requirements.**

Any electric utility which fails to comply with the requirements of §292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

[45 FR 12236, Feb. 25, 1980. Redesignated by Order 541, 57 FR 21734, May 22, 1992]

#### **§ 292.402 Waivers.**

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of subpart C (other than §292.302 thereof).

(b) *Commission action.* The Commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

[45 FR 12236, Feb. 25, 1980. Redesignated by Order 541, 57 FR 21734, May 22, 1992]

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## **Title 18: Conservation of Power and Water Resources**

### **PART 292—REGULATIONS UNDER SECTIONS 201 AND 210 OF THE PUBLIC UTILITY REGULATORY POLICIES ACT OF 1978 WITH REGARD TO SMALL POWER PRODUCTION AND COGENERATION**

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#### **Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations**

#### **§ 292.601 Exemption to qualifying facilities from the Federal Power Act.**

(a) *Applicability.* This section applies to qualifying facilities, other than those described in paragraph (b) of this section.

(b) *Exclusion.* This section does not apply to a qualifying small power production facility with a power production capacity which exceeds 30 megawatts, if such facility uses any primary energy source other than geothermal resources.

(c) *General rule.* Any qualifying facility described in paragraph (a) of this section shall be exempt from all sections of the Federal Power Act, except:

(1) Sections 205 and 206; however, sales of energy or capacity made by qualifying facilities 20 MW or smaller, or made pursuant to a contract executed on or before March 17, 2006 or made pursuant to a state regulatory authority's implementation of section 210 the Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 824a-1, shall be exempt from scrutiny under sections 205 and 206;

(2) Section 1-18, and 21-30;

(3) Sections 202(c), 210, 211, 212, 213, 214, 215, 220, 221 and 222;

(4) Sections 305(c); and

(5) Any necessary enforcement provision of part III of the Federal Power Act (including but not limited to sections 306, 307, 308, 309, 314, 315, 316 and 316A) with regard to the sections listed in paragraphs (c)(1), (2), (3) and (4) of this section.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.*; E.O. 12009, 42 FR 46267)

[Order 135, 46 FR 19232, Mar. 30, 1981, as amended by Order 569, 59 FR 40470, Aug. 9, 1994; Order 671, 71 FR 7868, Feb. 15, 2006; 72 FR 29063, May 24, 2007]

**§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.**

(a) *Applicability.* This section applies to any qualifying facility described in §292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 2005.* A qualifying facility described in paragraph (a) of this section or a utility geothermal small power production facility shall be exempt from the Public Utility Holding Company Act of 2005, 42 U.S.C. 16,451-63.

(c) *Exemption from certain State laws and regulations.* (1) Any qualifying facility shall be exempted (except as provided in paragraph (b)(2)) of this section from State laws or regulations respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State laws and regulations implementing subpart C.

(3) Upon request of a state regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in paragraph (b)(1) of this section.

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

(Energy Security Act, Pub. L. 96-294, 94 Stat. 611 (1980) Public Utility Regulatory Policies Act of 1978, 16 U.S.C. 2601, *et seq.*, Energy Supply and Environmental Coordination Act, 15 U.S.C. 791, *et seq.*, Federal Power Act, as amended, 16 U.S.C. 792 *et seq.*, Department of Energy Organization Act, 42 U.S.C. 7101, *et seq.* ; E.O. 12009, 42 FR 46267)

[45 FR 12237, Feb. 25, 1980, as amended by Order 135, 46 FR 19232, Mar. 30, 1981; Order 671, 71 FR 7869, Feb. 15, 2006; Order 671-A, 71 FR 30589, May 30, 2006]

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February 2008

# **Competitive Electricity Markets: The Benefits for Customers and the Environment**



**NERA**  
Economic Consulting

This white paper was commissioned by the COMPETE Coalition, which represents electricity customers, retail suppliers, power marketers, and generators. This paper represents the views of its authors and not necessarily the views of the COMPETE Coalition, its members, or the employer of the authors.

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## FOREWORD

**Alfred E. Kahn**

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Students and serious practitioners of public utility regulation have long recognized what an imperfect institution it is. Grounded in the conception that these industries are naturally monopolistic—that is, that full achievement of their inherent economies of scale requires that they be organized as franchised monopolies—it followed that they had to be regulated in order to protect consumers from exploitation, while at the same time assuring investors recovery of their prudently (more precisely, in practice, their not-demonstrably-imprudently) incurred costs.

This essentially cost-plus system appeared to work well in electric power during the quarter century following the end of World War II, when technological progress and the progressive realization of economies of scale in generation and transmission, and the adoption of nuclear generation, converged to produce declining rates in real terms. In the decades following 1973, in contrast, two bouts of double-digit inflation in the economy at large, two quadruplications of the price of oil, sharp increases in the cost of capital—especially painful in so capital-intensive a business—and massive cost overruns in nuclear facilities all compelled dramatic rate increases throughout the 1980s, just when a slump in the real prices of oil and natural gas and the advent of combined-cycle gas generation made deregulation and competition look far more attractive to consumers than continued compliance with the historic regulatory bargain.

As this brief historical account demonstrates, the movement for deregulation in the last decades of the 20<sup>th</sup> century was clearly opportunistic—putting pressures on regulatory agencies to renege on their implicit promise to set rates sufficient to provide fair returns on invested capital—a “temptation of the kleptocrats,” as I put it at the time.<sup>1</sup> Significantly, the pressures for deregulation were most insistent in states whose electric companies had invested heavily in nuclear plants and, at the other extreme, virtually nonexistent in states still relying heavily on coal, and particularly coal-fired generating plants that had long since been totally depreciated on the companies’ books.

But, clearly, there were fundamental, not merely transient issues at stake as well. As I observed some seventeen years ago, in the context of reforming regulatory practice rather than deregulation:

[A] consistent use of current competitive market valuations, for successful and unsuccessful investments alike, would be not only unobjectionable but desirable, because it would transfer the cost of failures, symmetrically with the profits of success, from ratepayers to investors.<sup>2</sup>

Manifestly, genuine deregulation would produce the same beneficent result.

Deregulation alone, however, would not take into account the especial importance, in this industry—in which only limited storage of its product is possible—of reliability of supply in the face of demand that fluctuates widely. Under regulation, this reliability was secured by requiring generators to maintain some stipulated margin of excess capacity sufficient to hold loss-of-load probabilities down to some acceptable minimum—the cost of which had to be distributed among all customer groups, since all benefited from it.

It was rarely recognized, however, that such a system was itself highly inefficient, because it failed to recognize that *individual customers* have widely differing needs for such assurances, because they differ correspondingly in the ability to adapt their consumption habits to the widely varying marginal costs. Only a system that provides customers with the choice of contracting with suppliers for such assurances as each of them requires—and its corollary, able instead to alter their consumption habits in response to changes in system marginal costs—can accomplish the purpose, on the one hand, of determining what margin of excess capacity is required in the aggregate and, second, how its costs will be distributed among customers. I commend to readers the authors' exposition of how restructured markets would, by confronting customers with prices varying hourly with contemporaneous marginal costs, give them the opportunity to react in real time, thereby giving each the opportunity to choose the level of reliability he or she wants and is willing to pay for.

Just as the move to restructuring was opportunistic, so too is the current sentiment to return to regulation a reaction to transient developments—in particular, the sharp increase in oil and gas prices—driving marginal costs above historic costs. But the choice of system should not be based, opportunistically, on transient events: the real defect of regulation is that rates set under it are based necessarily on averages—over time and among groups of customers. Ideally, the system would confront each customer with the proper price signals. And production efficiency is best realized when investors bear responsibility for investment decisions.

Policy makers confronting pressures to undo the restructuring of the electricity industry would be well advised to base their decisions on the longer-term benefits that will flow from properly implementing competitive markets, rather than on adventitious circumstances driving market prices temporarily above or below regulated rates.

#### Endnotes:

1. Alfred E. Kahn, *Letting Go: Deregulating the Process of Deregulation, or: Temptation of the Kleptocrats and the Political Economy of Regulatory Disingenuousness* (Institute of Public Utilities and Network Industries, Michigan State University, 1998).
2. Alfred E. Kahn, "The Changing Focus of Electric Utility Regulation," *Research in Law and Economics*, Vol. 13, p. 223 (1991)

**Alfred E. Kahn**

## I. EXECUTIVE SUMMARY<sup>1</sup>

State policy makers are reviewing past decisions to promote competition in electricity markets and, in some cases, are debating whether to reverse course. Competitive electricity markets, also known as “restructured electricity markets,” refer to the organization of the electric industry in states where utilities no longer have the obligation to plan and build generating capacity, and have often divested generation ownership. The purpose of this paper is to present an objective review of both traditional regulation and competitive electricity markets in order to assist policy makers as they critically assess their policy options.

The end of transition periods featuring rate caps and the onset of market-based retail rates has resulted in price increases for some states. While many have attributed these price increases to a failure of competition, the timing of the price increases is a coincidence and does not equate to causality. Electricity prices, driven by fuel costs, have risen in all states, not just those that restructured their electricity markets. As a result of these price increases, some states are examining their experiences with electric industry restructuring.

Prices derived by competitive markets and rates derived by traditional regulation<sup>2</sup> are fundamentally different, and will produce different outcomes. Over time, competitive markets are widely held to produce the most efficient results in our economy, providing the lowest costs to customers. Markets reward innovation—the search for and discovery, development, adoption, and commercialization of new products, services, organizational structures, processes, and procedures—that meets market demand. In a competitive environment, customers have more control over what they consume and what they pay, price levels will encourage more efficient use of energy, and market prices will encourage more demand response. Economists and experienced regulators, as well as national electricity policy, favor reliance on competitive markets when workable competition is feasible. It is important to evaluate the attributes of the competitive and cost-based regulatory models, and to critically analyze the strengths and weaknesses of each.

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<sup>1</sup> This white paper was prepared primarily by Eugene T. Meehan, a Senior Vice President at NERA, with Wayne P. Olson, a Senior Consultant at NERA. We thank Joshua Rogers for his research and editorial help. The opinions expressed herein are solely attributable to the authors and do not necessarily present a view of the firm or of other NERA professionals.

<sup>2</sup> Traditionally regulated utilities have an obligation to serve under traditional cost-of-service regulation, and to make and implement long-term generation plans in order to provide efficient, safe, adequate, and reliable service over time. It is important to note that even in restructured states, where such a model has been abandoned, there are many residual elements of traditional regulation. Transmission and distribution delivery service prices are regulated, and while customers receive a market-based generation price, the market procurement method is regulated.

Competition facilitates the most efficient means of production. Competitive market pricing provides significant benefits not found under traditional regulatory pricing. Among these benefits are the following:

- Market-based price signals are transparent and can stimulate appropriate infrastructure investment, energy conservation, and demand response.
- Competition provides customers with choices—i.e., customer sovereignty. Customers can exercise their own choices with respect to long-term risks, environmental concerns, and even reliability levels.
- Competitive market pricing allows sellers to tailor products and services to their customers' needs, and use demand-side solutions to avoid supply-side investment where appropriate.
- By pricing at market, prices will be similar for proximate utilities.
- Competition shifts risks from customers to investors.
- Competition produces more efficient results because the investor, not the ratepayer, assumes the generation investment risk.
- In competitive markets, poor producers fail and are acquired or replaced by those with more skill, foresight, and industry.

The electric utility industry pursued competition not for academic reasons, but because regulation was producing unacceptable outcomes, including large price differences between proximate utilities, large plant cost overruns, rate shocks and phase-ins, and customer dissatisfaction with lack of control over their electricity costs. Some innovative pricing concepts were studied, but they were rarely implemented on a large scale, and offerings were limited to a few standard tariffs. New generation built under regulation was considered too risky by both customers and investors, and power plants, particularly nuclear generators, demonstrated poor operating performance.

The differences between cost-of-service regulated rates and prices derived from competition are predictable and certain, and include the following:

- Regulated rates are founded on utilities' and regulators' judgment about the attributes of the product (e.g., reliability, environmental impacts) rather than the discipline of market forces.
- Regulated rates result in utilities and regulators imposing their choices on customers.
- Cost-based regulation makes it difficult for customers to make choices based on their own preferences and responses to market price signals.

- Cost-based regulated prices distort price signals necessary for efficient consumption, and undermine incentives for conservation and demand response. This creates a need to develop complicated and expensive conservation programs that “correct” the price signals through administrative means, when efficient results are obtained with simpler programs and market-derived prices.

Before undoing competitive markets, either intentionally or inadvertently, policy makers should consider the following facts:

- Regulated-monopoly generation imposed huge cost burdens on customers. These burdens, to which customers were exposed under the last significant non-gas capacity expansion, are what led many “high cost” states to restructure. In many states, cost-based regulation failed to produce reasonably priced electricity in the 1980s.
- States continuing with the regulated monopoly model are providing, and must continue to provide, iron-clad cost recovery guarantees for new generation investment.
- Transparent market prices derived in competitive markets are encouraging penetration of energy efficiency (conservation) and facilitating responsive consumer demand, lowering investment needs and providing environmental benefits.
- Innovations in end-use efficiency can potentially be created when customers control their own choices based on available information, and the market provides creative solutions. This can happen to the full extent only in a competitive market.
- Competitive electricity markets have led the way in developing renewable generation.
- Recent price increases are largely driven by fuel price increases, and have occurred in both competitive and traditionally regulated states.

While the promotion of competitive markets may not have been implemented perfectly, the points above suggest that customers would be better served by regulatory efforts directed at refining and improving the competitive model, rather than returning to cost-of-service regulation.

## II. INTRODUCTION

Over \$400 billion of electric industry infrastructure investment in generating plants will be required between 2006 and 2030.<sup>3</sup> Investments will be needed not only to accommodate the growth in population and the economy, but to replace aging facilities,<sup>4</sup> reduce emissions, fund research and development of innovative technologies, and lessen dependence on the use of liquid fuels from politically unstable foreign sources. In addition, all of these factors must be viewed in the context of heightened interest in renewable energy.<sup>5</sup> With such a large investment at stake, efficiency must be maximized and customers' interests must be protected. A failure to make this investment in the most efficient manner will: (1) make it difficult to ensure affordable and reliable electricity supply; (2) threaten the global competitiveness of the United States; and (3) risk having the country fall short of achieving environmental objectives.

To induce the needed investment, two economic models—that are markedly different both in terms of how they work and the incentives that they provide—can be used. The first is competition. In competitive markets, investors evaluate alternatives, make investment decisions, and place their capital at risk to market forces. Poor investment decisions lead to investor losses, even if such decisions were reasonable at the time they were made. The second model is cost-of-service regulation. In traditionally regulated markets, decisions about the type and timing of generating plant additions are generally determined by utilities, which are overseen by utility regulators. A utility builds, owns, and operates its system subject to oversight by the regulator through an open process that allows for significant input by stakeholders. While utility investors assume a limited set of investment risks, customers assume more, as they ultimately fund and support the investments through the rates they pay. Customers typically bear the risk when the selected investment incurs relatively higher costs, leading to rates that exceed market levels—so long as the utility's actions were prudent, meaning the actions were reasonable given available information.

At the national level, electricity policy is clear. Federal law provides for competition in wholesale generation markets and open access to transmission facilities. While this policy accommodates wholesale competition, it does not mandate or promote competition at the retail level. States have the choice to rely on vertically integrated utilities to plan, build, and own generating plants; to require utilities to use their monopoly position to underwrite long-term contracts that provide cost recovery without regard to how costs compare to the market in the future;<sup>6</sup> or, to transfer the responsibility for investment decisions and the risk of investment

<sup>3</sup> “[T]otal of 258 gigawatts of new [generating] capacity is expected between 2006 and 2030, representing a total investment of approximately \$412 billion (2005 dollars),” *Annual Energy Outlook 2007*, Energy Information Agency, DOE/EIA-0383, 2007.

<sup>4</sup> In the Northeastern US, about 41,000 megawatts of generation capacity are due to be retired, which is about one-quarter of generating plant in the region. See: Hugh Wynne, *U.S. Utilities: Capacity Retirements, Generation Investment and Technology Choice*, Bernstein Research, August 2006.

<sup>5</sup> Over the next five years, renewables comprise about 16 percent of the new generation that has been proposed; wind comprises 88 percent of proposed renewables. See: Dan Ford, *Just the Beginning*, Lehman Brothers (Power & Utilities), August 21, 2006, p. 8.

<sup>6</sup> The key phrase here is “in the future.” Regulated monopolies have to reasonably plan in this day and age, but the standard by which they are judged is whether their decisions were reasonable based on what a prudent utility

decisions away from customers and on to investors by adopting a competitive model. These state decisions on whether to use cost-of-service regulation, competition, or some mix of the two are critical to achieving efficient investment, promoting environmental goals, and protecting customer interests.

Choosing between competition and cost-of-service regulation is not easy. It can be difficult to fully appreciate the consequences of these two options. Given the long-lived nature of utility assets, the choice will have long-term financial and environmental consequences for energy customers. The United States, with its federal system of government, is unique among nations in reserving this major economic choice for the individual states. Policy makers undoubtedly face difficult challenges in the current environment, with price increases largely driven by input price increases, which have little to do with whether or not there are competitive power markets in the state.

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management could have known at the time. If, in the future, the regulated utility's costs become uneconomic relative to the market price, the utility would still be able to recover its actual, prudently-incurred costs in rates.

### III. THE CHOICE BETWEEN TRADITIONALLY REGULATED AND COMPETITIVE MARKETS IS CLEAR

Under competition, prices reflect the supply and demand conditions at the time, and customers have the ability to choose products and services that allow them to manage their individual electricity usage. Under cost-of-service regulation, customers enter into an ongoing long-term contract to support new generating investment through their local utilities, and have very little product choice. Prices reflect historical costs and historical investment decisions, not prevailing market prices.

Competitive market pricing provides many benefits not found under traditional regulatory pricing. First, because investors are compensated based on the market and not cost, they bear the risks and rewards of generation investment. Second, price signals are more accurate within competitive markets, and can stimulate appropriate infrastructure investment, energy conservation, and demand response. Markets use these price signals to evaluate solutions to current and future energy challenges. Third, competitive market pricing allows sellers to tailor products and services to their customers' needs, and use their ability to respond to prices in a way to avoid new investments where appropriate. Lastly, by pricing at market, prices will be similar for proximate utilities. Consequently, industries located in different utility territories will not be subject to arbitrary cost disadvantages relative to competitors, a balance that represents a change from cost-of-service regulation. Under the latter, if one utility decided to build a nuclear plant that resulted in a large but prudent cost overrun, while the neighboring utility decided on a coal plant that was built within budget, rates for the two utilities could differ sharply. This is not typical of functioning markets, and it is difficult for customers, particularly industrial competitors, to accept such arbitrary pricing.

Regulated prices are based on cost of service, and to the extent that different utilities make different investment decisions, prices for proximate utilities may be very different. Throughout the 1980s and 1990s, regulated prices were far above market. Once gas prices declined and technology developments in combined cycle generation lowered cost and heat rates, the cost of nuclear investments and Public Utility Regulatory Policies Act of 1978 (PURPA) qualifying facility (QF) contracts exceeded the cost of constructing and operating new combined cycle plants, or taking advantage of surplus capacity. Prices charged by proximate utilities differed based on the timing of their plant additions and construction cost outcomes.

Luck played a large factor in determining the rates that particular electricity customers paid. But one thing is certain: the major driver for the move to competitive electricity markets in the 1990s was the series of poor outcomes that occurred during the 1970s and 1980s, when the inclusion of "lumpy" investments in nuclear generating plants led to concerns about "rate shock," rate increase, phase-in plans, and automatic pass-through of fuel costs. Ratepayers and investors shared in the financial burden resulting from these investment decisions.<sup>7</sup>

<sup>7</sup> The economic losses resulting from the mistakes of the 1970s and 1980s may have cost as much as \$100 billion. See: Wald, "Nuclear Plant Drain Put at \$100 Billion for U.S.," *New York Times*, February 1, 1988, p. D1. This article was cited in Richard Goldsmith, "Utility Rates and 'Takings,'" *Energy Law Journal*, Vol. 10, No. 2, 1989, p. 241.

There is little reason to believe that a return to traditional regulation would lead to prices that would be continually below or at market levels. The only assured outcome is that cost-of-service regulated prices will reflect historical costs, not the market. Regulated prices could be administratively set to be relatively stable, but this may come at the cost of consistently failing to reflect the actual costs incurred. It makes little sense to attempt to choose between a traditionally regulated and a competitive model based on expectations of future price level differences, as such a choice would be speculative.

In competitive markets, where larger customers face hourly market prices (and smaller customers may elect to do so), electricity providers in many instances offer creative packages to satisfy customers. These are tangible differences between the traditionally regulated and competitive models that are predictable and certain. It is also certain that under competition, customers will have more control over what they consume and what they pay, that price levels will become known and encourage more efficient use of energy, and market prices will encourage the development of more responsive demand. Moreover, the same benefits apply to supply as well as to demand alternatives. For example, in a traditionally regulated model, wind resources will be viable only to the extent that a utility chooses to build or buy wind. In a competitive market, wind developers will have access to regional transmission organization (RTO) transmission and integration service, and will see market incentives to develop projects that provide maximum market benefits. Correspondingly, consumers may elect to buy more energy from wind and other renewable resources.

In competitive markets, generation investment decisions are made by investors in response to customer needs. Investors bear the risk of those decisions. This is a fundamental and important difference between competitive markets and cost-of-service regulation. It is important to consider that bearing risk does not equate to simply absorbing losses. There is an upside and a downside to risk. In return for bearing losses on unsuccessful investment decisions, investors realize gains on successful investments. That is the competitive model that prevails throughout the US economy.

There are other differences between cost-of-service regulation and competition that are predictable and certain. For instance, regulation requires utilities and, in turn, regulators, to substitute their judgment about the attributes of the product (e.g., reliability, environmental impacts) for that of the market, and this makes it difficult for customers to make choices based on their own preferences. Competition gives customers greater choice and control through market-based innovation. Customers can exercise their own choices with respect to environmental attributes, long-term risks, and even reliability levels. Regulated prices also typically distort price signals that are necessary for efficient consumption, and undermine incentives for conservation and demand response. Since the mid-1970s, traditionally regulated utilities have investigated innovative pricing and demand control. Progress has been limited, as regulated tariffs are standard and creative pricing schemes reflecting individual circumstances are hard to implement.

#### IV. ELECTRICITY COMPETITION WAS PURSUED AS A SOLUTION TO LONG-TERM PROBLEMS

Policy makers should consider that electricity markets were restructured because regulation was producing high prices and generally unacceptable outcomes for both customers and shareholders. This section will explain the cost-of-service regulation problems that began in the mid-1970s, which include price differences between proximate utilities, plant cost overruns, rate shocks and phase-ins, PURPA excess costs, and customer dissatisfaction with the lack of control over their electricity costs. Power plants, particularly nuclear plants, demonstrated poor operating performance.<sup>8</sup> Demand side measures and innovative pricing were frequently discussed but rarely implemented successfully in the traditionally regulated environment. By the mid- to late-1980s, there was substantial dissatisfaction with the outcomes of the regulatory process, which led policy makers to pursue competition in the 1990s.

These well-known regulatory problems, which began in the mid-1970s, created a strong impetus for the industry to restructure. A significant component to the problems was price, which, as Professor Paul Joskow of MIT notes, “reflected the high capital costs and poor operating performance of nuclear power plants commissioned during the 1970s and 1980s, the high prices reflected in PURPA/QF contracts, and the costs of excess capacity which got rolled into regulated prices.”<sup>9</sup> It is reasonable to assume that the same or similar problems could arise in states that revert to a system akin to traditional regulation. Problems with traditional, cost-of-service regulation of generation are still relevant in many parts of the United States.

US power systems were, for the most part, developed by vertically integrated utilities. These utilities built, owned, and operated distribution, transmission, and generation facilities. Traditionally, these utilities had exclusive service territories and the right to exclude other entities from the use of their distribution and, to a lesser extent, transmission facilities. The generation investment by these utilities was made pursuant to an obligation to serve all loads in the service territory. The legal framework provided for the right to charge rates that allowed the utility a reasonable opportunity to recover all prudent investments and costs incurred to meet that obligation, and further protected that investment with an exclusive service territory and the right to exclude others from the use of distribution facilities.

Major nuclear plant cost overruns received a large amount of press in the 1970s and 1980s. Regulators no longer wanted to deal with overseeing ratemaking issues years after an investment had been made in a plant. To cite some examples:

- In Ohio, construction of the Zimmer nuclear power plant began in 1969, with an estimated in operation date of 1975. Cincinnati Gas & Electric, Dayton Power & Light,

<sup>8</sup> Statistics show that there has been substantial improvement in nuclear operating performance in recent years. This is most easily represented by the increase in average capacity factor across the US nuclear power industry. The Nuclear Energy Institute provides public access to these statistics on its website. Please see: [http://www.nei.org/resourcesandstats/nuclear\\_statistics/usnuclearpowerplants/](http://www.nei.org/resourcesandstats/nuclear_statistics/usnuclearpowerplants/) (Accessed 11/28/07).

<sup>9</sup> Paul L. Joskow, *U.S. Energy Policy During the 1990s*, prepared for the conference “American Economic Policy During the 1990s,” sponsored by the John F. Kennedy School of Government, Harvard University, June 27 to June 30, 2001.

and Columbus and Southern Ohio Electric made up the ownership group, which predicted that the total cost of construction would be \$240 million. There were massive cost overruns after construction began, and the estimated total cost rose to \$3.5 billion, while the operating date became uncertain. Following allegations of mismanagement and intervention by the Nuclear Regulatory Commission, the owners announced that the plant would be converted to a coal-fired unit with an estimated completion date of 1991 at an additional cost of \$1.7 billion.<sup>10</sup>

- In Michigan, construction of the Midland nuclear power plant was expected to be completed by 1975 at a cost of \$276 million. Instead, construction of the plant was halted in 1984, after total costs had risen to \$4.2 billion. In 1986, the Michigan Public Service Commission decided that the plant should be converted to a gas-fired unit, with a conversion cost of \$600 million.<sup>11</sup>
- In New York, construction of the Nine Mile 2 plant began in 1970. The total cost for this project was initially estimated to be under \$400 million, and the facility was projected to be operating by 1977. These estimates changed dramatically after construction began, with total costs reaching \$3.7 billion and a completion date of 1986. The total cost of the plant after completion in 1986 was \$5.4 billion, of which \$4.45 billion was deemed recoverable by the New York Public Service Commission.<sup>12</sup>

There are many other examples of cost overruns, which led to a great deal of regulatory frustration over how to better deal with the construction and financing of generation. These frustrations stemmed from problems with nuclear power plants that experienced huge cost overruns, the aftermath of the energy crises of the 1970s, sharply reduced electricity demand growth rates, and the basic fact, that under the traditional regulatory compact, customers bore the vast majority of the risk.

In response to the regulatory issues, state regulators began to emphasize long-term "integrated resource planning" (IRP), which sought to improve on traditional *ex post* regulation by adding an *ex ante* component.<sup>13</sup> IRP began with the best of intentions—to do utility regulation "right," before the fact. Some regulators decided to use a forward-looking regulatory planning process in an attempt to acquire the least costly resources. At the same time, there was a redoubled emphasis on *ex post* scrutiny of the prudence of generation construction programs before new plants were allowed into the rate base.

<sup>10</sup> Charles F. Phillips, Jr., *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Reports, Inc., 1988), pp. 33-34.

<sup>11</sup> *Id.*

<sup>12</sup> Leonard S. Goodman, *The Process of Ratemaking* (Vienna, VA: Public Utilities Reports, Inc., 1998), pp. 866-867.

<sup>13</sup> Paul Joskow points out that PURPA was "accompanied by the creation of public 'integrated resource planning' (IRP) or 'least cost planning' (LCP) processes to determine 'appropriate' electric utility investment and contracting strategies which were eventually implemented with competitive bidding programs .... The rationale for and economic consequences of these programs were controversial." Joskow, *supra* note 9.

By the late 1980s, many utilities that needed new generation supply were required to procure this supply through competitive bid processes and IRPs. By 1990, 27 states had mandated or allowed the use of utility competitive bidding processes for generation resource procurement.<sup>14</sup> Utility participation in these bidding processes depended on state policy. In some cases, they were required to bid through an affiliate, submitting either a fixed-price bid or a proposal to build a rate-base generating facility, where the costs were not fixed. In either case, they would need to justify the selection of the winning bid to the regulator, and they were competing against non-utility providers.

Under traditional regulation, whether generation was built by the utility or by a new entrant, long-term commitments at ratepayer expense were provided to support the construction of long-term generating assets. If built by the utility, the assumption was that the asset would stay in the utility rate base until it was no longer used and useful, which could be 30-50 years. If built by an independent power producer under PURPA, with pricing based on avoided cost (the cost that the utility avoided by building the generation resource itself), the utility was frequently required to sign a long-term contract—sometimes as long as 15 to 30 years—to support the resource. Moreover, counter-party risk was not always adequately recognized, so the decisions that regulators made as part of the IRP process had major ramifications for utilities, new entrants, and electricity users over very long periods of time.

In addition to nuclear cost overruns, PURPA contracts were also burdening customers. As an example, Regulatory Research Associates notes that “[o]n March 10, 1997, NMK and 19 IPPs announced that a Master Restructuring Agreement was reached ‘in principle’ to restructure or terminate 44 purchased power contracts” and that “under the MRA, NMK would restructure or terminate the 44 power contracts in exchange for approximately \$3.6 billion in cash and/or debt securities and 46 million common shares, representing about 25% of NMK’s outstanding common shares.”<sup>15</sup>

The experiences of the past are especially relevant today. Plant construction costs have escalated sharply as more utilities are adding generation, making it more important than ever that existing resources be used efficiently, and that demand response and energy efficiency programs be pursued when it is economical to do so. The expected cost of building a new nuclear plant, for example, is escalating as a result of “massive inflation in copper and nickel and stainless steel and concrete.”<sup>16</sup> Part of the reason for the 25%-30% increase in the estimated cost of a coal-fired plant is the “huge price increases for the raw materials that plants are made from, including copper and nickel,” as well as the cost of finishing those commodities into components.<sup>17</sup> Electricity prices are increasing and, just as in a competitive market, regulation does not shield

<sup>14</sup> Steven Ferrey, *Law of Independent Power* (Deerfield, IL: Clark-Boardman, 1996), p. 9-3. Ferrey cites the National Independent Energy Producers, “Bidding for Power: The Emergence of Competitive Bidding in Electric Generation,” March 1990, p. 11.

<sup>15</sup> Regulatory Research Associates, Inc., *Regulatory Focus – Niagara Mohawk Power Final Report*, April 23, 1998.

<sup>16</sup> See: Matthew L. Wald, “Costs Surge for Building Power Plants,” *New York Times*, July 10, 2007.

<sup>17</sup> *Id.*

customers from rising input costs. Though costs may be deferred for a period of time due to the regulatory process, they will be recovered so long as they were prudently incurred.

## **V. COMPETITION HAS CLEAR ADVANTAGES OVER TRADITIONAL REGULATION AND HAS ALREADY BEGUN TO PROVIDE EFFICIENCY AND ENVIRONMENTAL BENEFITS**

Competitive electricity markets allow consumers to choose among providers and service options. This combination of open entry for suppliers and choice for customers provides the benefits of competitive markets (e.g., efficient resource allocation, accurate price signals, and incentives for innovation) and limits competitors' ability to exercise market power. Customers are protected from open-ended commitments to pay above-market costs that would not be passed through in a competitive market. This does not mean that entry into markets will be costless or easy, but rather that all actual competitors, incumbents and new entrants alike, will have made (and potential competitors could make) the investments and commitments necessary for them to compete in the market. Under this system, customers are free to manage long-term risk, which, for example, could include entering into long-term contracts with electricity suppliers.

Under traditional regulation, vertically integrated utilities build new generating plants in order to serve customer demand. Through the regulatory least-cost planning process, utilities are given permission to pursue resource procurement strategies, which effectively commit the regulator to pass the resulting costs through to customers so long as the utility has acted prudently in incurring those costs. This type of utility regulation includes both: (1) an *ex ante* component, requiring the utility to use least-cost integrated resource planning, and to get permission from the regulator before it commits to build or purchase new generating resources; and (2) an *ex post* component, requiring the utility to ask for a rate increase that puts the new plant into the rate base, and allows it the opportunity to earn its opportunity cost of capital on that rate base. Given the utility's obligation to serve, there is a corresponding regulatory obligation to pass through prudently incurred costs to customers, regardless of what those costs would have been in a competitive market.

**Table 1** includes a listing of significant differences between firms that operate in competitive and traditionally regulated models that policy makers should consider when deciding how to move forward.

**Table 1: Competitive Versus Traditionally Regulated Markets**

	<b>Competition</b>	<b>Traditional Regulation</b>
<b>Funding</b>	Company funds investments with the expectation that it will be able to charge customers prices that justify those costs.	Ratepayers fund prudently incurred investments in rate base with a virtual certainty of recovering the costs.
<b>Price Determination</b>	Prices set in a market by supply and demand with open-ended possibilities for pricing structures, which means choice for consumers.	Prices set based on cost with limited menu of regulated tariffs.
<b>Market Concentration</b>	Multiple firms compete with one another, with potential competitors providing competitive pressure as well.	Generally one firm, once with a franchise.
<b>What Is Built</b>	Companies, in response to customer demand, will be more likely to invest in less traditional and more energy-efficient forms of generation, including renewables.	Regulators approve what utilities build. This may or may not be the lowest cost investment, and may or may not be technologically innovative.
<b>Capital Structure</b>	Less use of leverage perhaps, reflecting greater investment risk, but more potential for innovative financing arrangements.	Traditional utility regulation accommodates the use of more debt, but limits innovation.
<b>Who Bears Risk of Bad Investments?</b>	Investors.	Consumers.
<b>Market Activity</b>	The competitive environment is dynamic and subject to entry and exit. This creates a powerful incentive for firms to increase operating efficiency.	Static. Subject to bureaucratic process.
<b>Cost Allocation</b>	Value branding. Independent power companies have a greater opportunity to market different services to different customers.	Cost averaging. Through the regulatory process, costs incurred are averaged out when determining rates, and the ratepayers that incur specific costs may not necessarily pay for them.
<b>Keys To Success</b>	Ability to compete on price, terms, and non-price attributes such as billing arrangements and product innovation (such as green power).	Prudence and accountability in decision making; competence working with regulatory and political policy. Ability to overcome market failures.
<b>Vertical Integration</b>	Greater vertical separation of regulated and competitive activities.	Typically vertically integrated, subject to an internal system of command.
<b>Ownership And Investment</b>	Risk and return expectations will be relatively higher. This will affect what types of entities hold ownership stakes.	Risk and return expectations will be relatively lower. This will affect what types of entities hold ownership stakes.
<b>Marketing</b>	Increased need for marketing, and development of innovative products. Focused on meeting individual customer needs through innovation.	Reduced need for marketing and business development. Largely focused on providing one-size-fits-all solutions for customers.
<b>Price Stability</b>	If price stability is desired by customers, competitive retailers will make such a product available.	The regulatory process eventually allows recovery of all prudent costs. Rates can be slow to respond to changing conditions due to regulatory lag.
<b>Price Signals</b>	Prices tend to reflect marginal costs, the most accurate representation of opportunity cost.	Retail prices can become distorted from marginal costs through the ratemaking process.

This table demonstrates the disparate characteristics of competitive and traditionally regulated markets. The fundamentals of a competitive market, such as having more than one supplier, feasible entry and exit, and enhanced price transparency, create these differences. These factors allow competition to spur reductions in operating expenses and increases in innovation.

Traditional regulation, although based on prudently incurred costs, can yield inefficient results, primarily due to the requirement that utility ratepayers bear the majority of risks, rather than investors.

### A. Competition Shifts the Risk to Investors

One of the benefits of restructured markets is that the investment risk for generation plants is shifting from consumers to investors. For instance, after restructuring, there was a huge initial burst of merchant construction in most areas of the country which, despite leading to excess capacity, did not cost customers a dime. This was an especially pertinent topic at the time of restructuring, as there were various notable examples of major cost over-runs in plant construction, especially with nuclear facilities.

Now, with many parts of the country expressing concerns about the adequacy of generation supply, certain states are pursuing policies aimed at providing incentives to build new generation. In competitive markets, wholesale prices provide the incentives to build new infrastructure, with customers free from the obligation to fund those investments. Many traditionally regulated states have recently passed laws providing for prior review of plant—cost recovery guarantees not available to merchant generators—and construction work in progress (CWIP) in rate base.<sup>18</sup> For example:

- **Florida:** In June 2006, legislation that affects several aspects of the state's energy policy was enacted. Senate Bill (S.B.) 888 exempts nuclear power plants from the requirement of a competitive bid and provides for recovery of pre-construction costs and a cash return on CWIP during the construction period of a nuclear power plant. A similar bill, House Bill (H.B.) 549, was enacted on June 12, 2007. This legislation authorizes deferred accounting for the pre-construction costs of integrated gasification combined-cycle (IGCC) plants, and these costs are to accrue a carrying charge equal to the utility's AFUDC rate. All prudently incurred pre-construction costs are recoverable through the utility's capacity cost recovery clause, as is a current return on CWIP.
- **North Carolina:** Senate Bill (S.B.) 3, which was enacted on August 20, 2007, facilitates the NCUC's ability to allow a cash return on CWIP by removing statutory language that had permitted utilities to earn a cash return on CWIP only "to the extent [...] such inclusion is in the public interest and necessary to the financial stability of the utility in question." As an example, the NCUC recently approved the recovery of pre-construction development costs for the proposed Duke Energy Lee Nuclear Station, stating that "to the extent the Commission finds, in a future general rate case proceeding, the specific activities involved in, and the costs of pursuing such Development Work to be prudent and reasonable (whether or not the Lee Nuclear Station is constructed), Duke may

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<sup>18</sup> CWIP in rate base, which provides cash before a plant operates, does not occur in competitive markets. For regulated utilities, there have been instances where commissions have allowed CWIP to be recovered when a regulated utility needs cash flow assistance or when Allowance for Funds Used During Construction (AFUDC) balances, which are "paper" earnings not "cash" earnings, grow large and become burdensome financially. Normally, however, CWIP in rate base is not allowed as the plant is not yet benefiting customers, but in order to induce utilities to build more states are formalizing CWIP allowances.

recover” the Development Work costs in rates.<sup>19</sup> These development costs are expected to total \$125 million.

- **Nevada:** In 2004, the PUC adopted revised integrated resource planning rules that permit the Commission to approve an incentive mechanism for generation facilities designated as “critical.” Under the rules, the PUC has the option to designate a project as critical if it protects reliability, promotes supply diversity, or utilizes renewable resources. For such a project, the utility may be awarded a financial incentive including: (1) an enhanced ROE on the designated critical facility over the life of the facility; (2) a cash return on CWIP associated with the facility; or (3) the deferral of costs incurred to construct the facility.
- **Wisconsin:** Through an ROE adder, the PSC generally allows a current return on 50 percent of a utility’s electric and gas CWIP, except for major generation projects where the PSC generally allows a current return on 100 percent of the CWIP associated with that project.<sup>20</sup>

The trend is clear: the US needs to build new generating capacity, greatly increase energy efficiency, or initiate a combination of both in order to meet demand for electricity and diversify the supply mix away from old technology. Cost-of-service regulation could accomplish this, but going down that path will necessitate iron-clad cost recovery assurances for increasingly expensive generation assets.<sup>21</sup> Regulated entities may be volunteering to build new generation, but not without cost recovery guarantees and payments before plants are in service. While the prior building cycle proved that recovery assurances need to be provided to investors, the amount of price risk faced by consumers does not seem to have sunk in. Customers may not yet be aware of the long-term commitments that are being made on their behalf by utilities and their regulators.<sup>22</sup>

## B. Economic Efficiency Gains

Reliance on competitive markets is based on the principle that firms with the most efficient production and the most value for consumers should and will prevail. Efficient competition leads to production at the lowest achievable costs in the long-term, which is a socially desirable outcome that results in an efficient use of society's resources. Currently, with

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<sup>19</sup> Regulatory Research Associates, Inc., Focus Notes, March 30, 2007. A similar approval was granted by the Ohio Public Utilities Commission to American Electric Power (AEP) in 2006, which allowed for the recovery of \$24 million in pre-construction costs related to an IGCC facility. See: Regulatory Research Associates, Inc., Focus Notes, April 27, 2007.

<sup>20</sup> Regulatory Research Associates, Inc., State Commission Overviews, various dates.

<sup>21</sup> From May 2005 to October 2006, Duke Energy’s estimate of construction costs for two new coal-fired plants at its Cliffside site went from \$2 billion to \$3 billion. The North Carolina Utility Commission ultimately approved a single plant for \$1.8 billion, an 80 percent increase from the initial estimate—and that number is still just an estimate. Similarly, Entergy’s cost to re-power its Little Gypsy site was estimated in April, 2007, to cost \$1 billion; by July, 2007 this figure had increased by over 50 percent to \$1.55 billion.

<sup>22</sup> We are not saying that such guarantees and cash flow allowances are unjustified or unnecessary. To the contrary they may be required in regulated situations. The point is that this is a major difference between the regulated and competitive solutions.

transition to competition periods beginning to end, it is too early to determine the ultimate success or failure of electricity competition—but it is possible to see some encouraging trends.

With competition, generation operators' incentives changed dramatically, leading to changes in microeconomic behaviour. Though they may not be immediately evident in prices, benefits are clear in non-price advantages such as greater service variety and the presence of a functioning market for capacity (which promotes efficient investment decisions).

Research papers that focus on measures of efficiency other than price, such as generator efficiency or operating cost reductions, offer a more complete indication of the impacts of competition in the current environment. Research has found that:

- Operating costs of generating plants in states that chose to restructure have been reduced relative to costs of generating plants in states that decided against implementing competition.<sup>23</sup> Plant operators affected by competition reduced labor and non-fuel expenses by about 3%-5% relative to other IOUs and 6%-12% relative to cooperatives or government-owned generation.<sup>24</sup> Similarly, divested generating plants and those subject to incentive regulation mechanisms improved their fuel efficiencies compared to their peers without high-powered incentives.<sup>25</sup>
- One of the benefits introduced by competition in generation was to improve the performance of previously existing generating assets in the face of competition. Availability, non-fuel operating costs, and heat rates improved significantly. Availability of generating capacity has increased over time in both New England and New York. Equivalent availability factors increased significantly in PJM from 1994 to 1998 and have been roughly constant since then with some year-to-year variability.<sup>26</sup> Relatively small efficiency gains—such as a two percent improvement in heat rates—can provide hundreds of millions of dollars of annual fuel savings.

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<sup>23</sup> Fabrizaio, K., N. Rose and C. Wolfram, "Do Markets Reduce Costs? Assessing the Impact of Regulatory Restructuring on US Electric Generation Efficiency," *The American Economic Review*, Vol. 97 No. 4, 2007.

<sup>24</sup> *Id.*

<sup>25</sup> Bushnell, J. and C. Wolfram, *Ownership Changes, Incentives and Plant Efficiency: The Divestiture of U.S. Electric Generating Plants*, University of California Center for the Study of Energy Markets, CSEM WP-140, March, 2004.

<sup>26</sup> Paul L. Joskow, "Restructuring, Competition and Regulatory Reform in the U.S. Electricity Sector," *Journal of Economic Perspectives*, 11(3): 119-138, 1997.

ISO New England, *2004 Annual Markets Report*, 2005, [http://www.ksg.harvard.edu/hepg/Papers/ISONE\\_2004\\_annual\\_markets\\_report.pdf](http://www.ksg.harvard.edu/hepg/Papers/ISONE_2004_annual_markets_report.pdf) (Accessed 11/2/07).

New York ISO, *2004 State of the Markets Report*, prepared by David Patton, 2005, [http://www.nyiso.com/public/webdocs/documents/market\\_advisor\\_reports/2004\\_patton\\_final\\_report.pdf](http://www.nyiso.com/public/webdocs/documents/market_advisor_reports/2004_patton_final_report.pdf) (Accessed 11/2/07).

PJM Interconnection, *State of the Market Report 2004*, 2005, <http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/pjm-som-2004.pdf> (Accessed 11/2/07).

Markets reward innovation—the search for and discovery, development, adoption, and commercialization of new products, services, organizational structures, processes, and procedures—that meets market demand. The role of competitors in the marketplace is to compete on the basis of price and value. While competing on the basis of price is obviously very important, successful competitors can also innovate and offer the customer something better than that offered by standard service. Some value-added services may be related to price, such as information services that improve a customer's ability to manage its energy usage. Value could also be provided in the form of green power, risk management (fixed prices for seasons or a year), bundling of services, or could take a form that is not currently anticipated.

### **C. Energy Efficiency and Renewables**

Energy efficiency, distributed energy resources (DER) programs, and renewables (e.g., wind) all benefit from transparent markets and the competitive incentives that restructured markets provide. In a competitive situation (with an RTO or ISO), it is more likely that price signals for generation services (energy, capacity, and ancillary services) will be market based, and it is also more likely that service providers or retailers will be involved.

#### **1. Market Transparency and Demand Response**

Innovative RTO/ISO programs are providing incentives for a wide variety of needed generation and transmission-related resources. The ISO-RTO Council, made up of ISOs and RTOs serving two-thirds of the US market and half of the Canadian market, recently issued three reports documenting the success they have had in terms of managing demand response programs and encouraging renewable investment.<sup>27</sup> The reports note various ways in which RTOs can facilitate renewable development including clear, expeditious, and nondiscriminatory interconnection processes and market-based ancillary services.

Demand response programs that respond to real-time prices can also serve to moderate spot price spikes. Demand response programs work best in transparent markets, which eliminate the need to use an administered-type price, such as avoided cost pricing, which may give very misleading price signals. With a transparent market providing price signals, it becomes possible to fairly evaluate energy efficiency, demand response programs, and renewable resources. Furthermore, ISOs, by definition, have no stake in market outcomes. Because they own no generation, they are neutral with respect to the ownership and types of generating units that operate within their system. The same is not always true for utilities.

#### **2. Availability of Information and Price Signals**

It is imperative for potential investors in renewable sources of energy to have access to detailed pricing information so that they can judge the feasibility of their projects. In regard to this, and in support of competition, the ISO/RTO Council reported: "ISO and RTO wholesale markets provide price transparency to inform all market participants, including renewable

<sup>27</sup> For more information, please see: ISO/RTO Council, *Increasing Renewable Resources*, October 16, 2007; ISO/RTO Council, *Progress of Organized Wholesale Electricity Markets in North America*, October 16, 2007; Markets Committee of the ISO/RTO Council, *Harnessing the Power of Demand*, October 16, 2007.

generation owners, about the price and the value of their power.”<sup>28</sup> In addition, the report notes: “[i]n wholesale electricity markets, developers have access to both historical data and forward price curves to estimate the future value of their generation.”<sup>29</sup> This lies in stark contrast to projects not in ISO/RTO regions, where it is likely that the developer will negotiate price bilaterally with the utility, and will not have access to public price information.

The availability of time-based market prices and demand response capability can change the energy cost structure faced by certain utility customers during peak periods, resulting in increased consumer price responsiveness (i.e., elasticity). Thus, customers participating in demand response programs benefit from transparent market prices. Through the market process of numerous buyers and sellers making individual decisions, competitive markets allow consumer demands to be sorted out and aggregated by producers at the lowest possible cost. The price information provided by the market gives buyers and sellers the information they need to make their individual production and purchasing decisions. The Markets Committee of the ISO/RTO Council issued a positive review of ISO/RTO management of the demand response programs in the US and Canada, stating that:

The markets these ISOs and RTOs administer, which represent approximately two-thirds of electricity demand across the United States and just over 40 percent in Canada, are playing an important and growing role in enabling demand response to reach its full potential. They provide visible price signals that will help consumers make rational decisions about expenditures on electricity in the same way they use market prices for deciding how to purchase other goods and services.<sup>30</sup>

Given the price signals provided by a transparent real-time spot market, demand response programs can be more effective in restructured jurisdictions. Efficiency investments are also spurred when customers see true market prices and can make decisions to use energy more efficiently based on those prices.

States with competitive markets can avoid relying heavily on administratively set credits that may not always adjust readily to reflect changes in costs. Administratively set credits have an important defect: they are *static* in nature, while wholesale power markets are inherently dynamic over time. In dynamic power markets, administratively set credits rapidly become stale and can trigger incorrect and outdated responses. One lesson from the implementation of PURPA in the 1980s is that, in the absence of market prices, setting avoided cost rates is a very difficult task to complete correctly. When wholesale market price information is readily available, these challenges are reduced.

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<sup>28</sup> ISO/RTO Council, *Increasing Renewable Resources*, October 16, 2007, p. 11.

<sup>29</sup> *Id.*

<sup>30</sup> Markets Committee of the ISO/RTO Council, *Harnessing the Power of Demand*, October 16, 2007, p. 1.

### 3. Renewable Generation Growth

The records on prices that are maintained by ISOs and RTOs can serve as valuable information to companies deciding whether or not to invest in renewable generation assets. But what has actually happened in recent times, in terms of the *growth* in generation from renewable resources in restructured vs. traditionally regulated states?

**Table 2: Growth of Renewable Generation in Restructured and Traditional States 2000-2005**

	Growth Rate
Restructured States	11.3%
Traditional States	0.6%

Source: EIA.

Total renewable generation increased in both markets during the period of time between 2000 and 2005. However, renewable net generation in restructured states increased by approximately 11.3 percent, while there has been an increase of less than one percent in traditionally regulated states. This is not to say that restructuring was completely responsible for the relatively larger increase in renewable net generation in restructured states. To prove this, a multitude of other variables would have to be considered, including overall trends in electricity demand, and separate state policies regarding renewables. These statistics are important, however, given the expectation that independent power providers compete based on short term marginal cost, and that renewables would therefore not be viable competitors. In addition, utilities in restructured markets are not mandated to purchase power from PURPA qualifying facilities.<sup>31</sup> At the very least, the growth in renewable net generation in restructured states shows that the transparent market prices, customer choice, and renewable standards that are available in restructured markets help to provide a favorable environment for renewables.

There have been many recent examples of renewables gaining a stronger foothold in restructured markets. For instance, in Maine, a proposed mountain ridge wind farm has already sold its first 10 years of renewable energy.<sup>32</sup> This project is expected to power 44,000 households and reduce daily air emissions in the region by 430 tons a day. Harley Lee, President of Endless Energy in Yarmouth, issued a statement that highlighted Constellation's role as a power marketer, noting that "[o]ur region has lagged behind other parts of the country in the use of

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<sup>31</sup> As part of the Energy Policy Act of 2005, Congress substantially narrowed the applicability and scope of QF must-buy requirements. Thus, utilities in much of the US will be relieved from the Section 210 requirements applicable to new QF facilities, with a showing that a new QF has nondiscriminatory access to competitive wholesale markets that meet the applicable standard. For utilities that cannot show that the new QF has access to competitive wholesale markets that meet the Section 1253 standard, the PURPA "must buy" requirements will continue.

<sup>32</sup> Donna M. Perry, "Redington Wind Farm has Deal to Sell Power," *Sun Journal*, April 6, 2006.

wind energy. A major reason has been the lack of a power marketer willing to sign long-term contracts.”<sup>33</sup>

Other positive examples of renewable energy in restructured states include an agreement between Constellation and Horizon Wind Energy for an 18-year renewable energy power purchase agreement,<sup>34</sup> a contract between Epuron LLC (Conergy) and Exelon Generation for a 20-year power purchase agreement for the energy produced at a proposed 3 megawatt (MW) solar energy power station in Morrisville, Pennsylvania,<sup>35</sup> and the success of PECO Wind in Pennsylvania.

## VI. CONCLUSION

State policy makers face a difficult situation. Restructuring transition periods have ended or are ending as prices are rising across the country. Prices have generally been rising over the past several years, regardless of market structure, primarily because of rising input fuel prices. At the same time, investment needs are growing and environmentally beneficial renewables are being mandated by legislation. Carbon emissions, which are not limited at all now, could be limited moving forward, which will further increase prices. Upward pressure on natural gas and oil prices show no signs of relenting. Even generation equipment costs are rising as the metals needed for their manufacture increase in price, and as demand drives up engineering and construction labor costs. Price increases are unpopular, and in the search for a villain, it is easy to blame competition. The facts, however, do not support the hypothesis that competition is the cause of price increases. The rise in oil and gas prices, equipment costs, impending carbon control costs, and the mandate to replace older and dirtier generation with alternative units are the primary factors behind these price increases. Both competitive and traditionally regulated states are seeing the impact of input price increases.

It is true that restructuring was misunderstood and, in many cases, unrealistic expectations may have been set. The implication that restructuring would always lead to lower prices was not accompanied by the obvious “all else being equal” or “over the long term” provisions. Abstracting from oil and gas prices, renewable mandates, equipment cost increases, and carbon reduction costs, it is likely that prices in restructured states would have declined as transition periods ended. But that did not happen, and industry structure cannot compensate for sharp increases in input prices.

In theory and in practice, restructured markets are superior in providing production efficiency incentives, in encouraging efficient demand side activity, and in encouraging investment in alternative forms of generation. We also know that in competitive markets customers bear much less risk. These factors all point to a policy that favors competition over

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<sup>33</sup> *Id.*

<sup>34</sup> Constellation Energy, *Constellation Energy to Purchase Wind Power From Horizon Wind Energy's Twin Groves II Project*, July 25, 2007, <http://ir.constellation.com/phoenix.zhtml?c=112182&p=irol-newsArticle&ID=1030961&highlight=> (Accessed 11/2/07).

<sup>35</sup> *Epuron, Exelon Join Forces on 3 MW Pennsylvania Solar Facility*, RenewableEnergyAccess.com, September 4, 2007, <http://www.renewableenergyaccess.com/rea/news/story?id=49828> (Accessed 11/2/07).

cost-of-service regulation. Electricity generation is a capital intensive industry with long lead times, and the benefits of competition cannot be expected to be seen overnight.

We also know that cost-of-service regulation performed poorly during the last major generation building cycle. However, these lessons, while very relevant, may not stand out to current policy makers who were not involved in the industry in the 1970s and 1980s. Competition, with all its imperfections and transitional problems, is too often compared to an idealized version of regulation that may exist in theory but not in practice.

Before rushing to judgment on restructuring and undoing competitive markets, policy makers should consider the following facts:

- Competition and cost-of-service regulation are fundamentally different and competition will shift risk from customers to investors.
- The risks borne by customers and the outcomes they were exposed to under the last significant non-gas capacity expansion are what led states to restructure. In many states, cost-of-service regulation failed in the 1980s.
- States continuing in the cost-of-service regulated model are providing iron-clad cost recovery guarantees for new generation investment and prudence pre-approval.
- The market prices seen in competitive markets will encourage efficient penetration of energy efficiency (conservation) and facilitate demand response, lowering investment needs, and providing environmental benefits.
- Competitive markets have led the way in renewable energy development.
- Recent price increases are largely driven by input price increases, and have occurred in both competitive and traditionally regulated states.

While restructuring may not have been perfectly implemented and there will always be room for improvement, the facts above suggest that regulatory efforts would be better directed at refining and improving the competition model rather than returning to the cost-of-service regulated model.

# LEGISLATIVE RESEARCH REPORT

MARCH 5, 2010



REPORT NUMBER 10.189

## REGULATION OF WHOLESALE TRANSACTIONS BY INDEPENDENT POWER PRODUCERS

PREPARED FOR SENATOR LESIL MCGUIRE

BY TIM SPENGLER, LEGISLATIVE ANALYST

You asked if other states regulate wholesale electric power transactions by independent power producers (IPPs) in the same way as does Alaska.<sup>1</sup> Specifically, you wanted to know if other states regulate power producers who sell to one or more customers and generate more than \$50,000 in income from the sale of electricity, as provided in Alaska law.<sup>2</sup> Briefly, we could identify no states that regulate independent power producers in this way.

For our review, we queried all state utility commissions, conducted a search of the Westlaw database of state statutes, and contacted national experts on the topic. None of the 24 states that responded to our query report having any regulatory language similar to that in Alaska.<sup>3</sup> A frequent response that we received from states was that IPPs are subject to Federal Energy Regulatory Commission (FERC) regulations but not to state regulation.<sup>4</sup> A number of experts we contacted point out that utilities that purchase electricity from IPPs are subject to their respective state's public utilities commission regulations. We also communicated with lead staff from the National Association of Regulatory Utility Commissioners (NARUC), the Independent Power Producers Coalition of the West (IPPC), the National Conference of State Legislatures (NCSL),

<sup>1</sup> Independent power producers are entities that generate electric power for sale to utilities and end users. The producers are unaffiliated with the franchised utility in the area in which the IPP is selling power

<sup>2</sup> The Regulatory Commission of Alaska has statutory authority (under AS 42.05.141) to regulate every "public utility." Public utility is defined under AS 42.05.990(4) as an entity (including an individual) that furnishes electrical service to the "public" for compensation. AS 42.05.990(2)(b) defines "public" or "general public"— as "one or more customers that purchase electrical service for use within an area that is certificated to and presently or formerly served by an electric utility if the total annual compensation that the electrical utility receives for sales of electricity exceeds \$50,000."

<sup>3</sup> Officials in the following 24 states responded to our query: Alabama, Arizona, Arkansas, Colorado, Hawaii, Idaho, Illinois, Iowa, Kansas, Kentucky, Maine, Maryland, Minnesota, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, North Carolina, Oregon, South Dakota, Texas, Virginia, and Washington.

<sup>4</sup> We spoke with FERC energy industry analyst, Saeed Farrokhpay, (916) 294-0322, who confirmed that IPPs' power transactions fall under FERC jurisdiction pertaining to rate regulation. The FERC is a federal agency, under the Department of Energy, with jurisdiction over interstate natural gas transportation and sale for resale rates, wholesale electric rates, hydroelectric licensing, oil pipeline rates, and gas pipeline certification (<http://www.ferc.gov>).

and the Colorado Independent Energy Association.<sup>5</sup> None of the experts from these entities with whom we spoke were aware of regulations in other states similar to those in Alaska. A common thread of the feedback we received was that regulating wholesale transactions of independent power producers would be a duplicative procedure as the utilities to which IPPs sell their electricity are already regulated by states. Such regulations would likely act as a disincentive for IPPs—including alternative or smaller energy producers—effectively discouraging such entities from engaging in business.

Below we highlight feedback we received from eight states that you may find to be of interest.

- ◆ **Arkansas:** According to Dave Stanton (501-682-1792), chief administrative law judge and chief of commissioners' staff, Arkansas Public Service Commission (APSC), the APSC only regulates "public utilities" and, therefore, has no regulatory authority over independent power producers. IPPs located in Arkansas are not subject to rate regulation but are subject to state and federal environmental regulations administered by the federal EPA and the Arkansas Department of Environmental Quality.
- ◆ **Colorado:** Colorado Public Utilities Commission does not regulate Independent Power Producers, according to Doug Dean (303-894-2007), director of the commission. IPPs are not allowed to provide retail electric services; they only provide electricity at the wholesale level. Only the investor-owned electric utilities, cooperative electric associations, and municipal utilities are permitted to provide retail electric service in Colorado. These entities are regulated by the state.
- ◆ **Idaho:** The state does not regulate independent power producers, regardless of size, according to Gene Fadness (208-334-0339), executive director, Idaho Public Utilities Commission (IPUC). The IPPs come under IPUC purview only when they contract with regulated utilities.
- ◆ **Maine:** Evelyn deFrees (207-287-6141), public information officer with Maine's Public Utilities Commission, relates that the state does not regulate power suppliers or producers, only transmission and distribution companies. The commission does license and oversee companies that sell at the retail level; at the wholesale level, however, the sale of electricity is not state regulated but is subject to FERC jurisdiction.
- ◆ **Minnesota:** The Minnesota Public Utilities Commission only has ratemaking authority over entities defined as public utilities, according to Janet Gonzales (651-201-2231), energy unit manager. Public utilities are (in part) defined in

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<sup>5</sup> We contacted the following individuals for this report: Christopher Mele, legislative director—energy, National Association of Regulatory Utility Commissioners, (202) 898-2206. NARUC is an association representing state public service commissioners who regulate utility services, such as electricity, gas, telecommunications, water, and transportation, throughout the country (<http://www.naruc.org>); Robert Kahn, executive director, Northwest and Intermountain Power Producers Coalition (NIPPC), (206) 624-1235. NIPPC's website asserts that the organization will pursue informal and formal (i.e., laws, policies, rules, and regulations) avenues and forums to encourage a competitive electric power supply marketplace in the Pacific Northwest and Intermountain West (<http://www.nippc.org>); Keith Hay, energy program director, National Conference of State Legislatures, (303) 364-7700 (<http://www.ncsl.org>); Nicholas Muller executive director, Colorado Independent Energy Association, (303) 297-1970. The CIEA attempts to save Colorado ratepayers money by promoting lower cost electricity (<http://www.ciea-colorado.org>).

Minnesota statute (§216B.02, subd. 4) in the following way: "No person shall be deemed to be a public utility if it produces or furnishes service to less than 25 persons." Minnesota does not regulate electric power providers based on revenues from electricity sales.

- ◆ **New Jersey:** Doyal Siddell (973-468-8515), public information officer, New Jersey Board of Public Utilities relates that power from New Jersey's independent power producers is dispatched to the state's regional transmission organization, PJM, whose rates are subject to FERC jurisdiction; the state has no jurisdiction.
- ◆ **Oregon:** Oregon does not regulate wholesale power transactions between independent power producers, according to Maury Galbraith (503-378-8718), electric rates and planning, Public Utilities Commission. Mr. Galbraith informs us that FERC has regulatory jurisdiction over this type of transaction across the country:
- ◆ **South Dakota:** John Smith (605-773-3201), general counsel, South Dakota Public Utilities Commission, informs us that their commission does not engage in utility regulation of independent power producers unless the IPPs sell to "ultimate consumers"—or, in other words, retail consumers.

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We hope you find this information to be useful. Please let us know if you have questions or need additional information.



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March 8, 2010

Senator Lesil McGuire  
Alaska State Legislature  
120 4<sup>th</sup> Street, State Capitol, Room 125  
Juneau, AK 99801-1182

Re: Senate Bill 277

Dear Senator McGuire:

The Alaska Power Association (APA) and its members have not yet had the opportunity to fully explore all of the potential impacts of the March 2, 2010, committee substitute for Senate Bill 277. However, based on its preliminary review, APA is concerned about the potential ramifications of this bill. At this point, APA cannot support SB 277 because of those concerns, but welcomes any opportunity to discuss those concerns with you or your staff. APA's concerns are summarized below:

**General Concerns Regarding Statutory Exemption:**

I. The exemption from RCA certification and regulation provided for in the bill may be unnecessary for the following reasons: First, under federal law, most renewable energy resource electric generation facilities that propose to sell power only to another electric utility can already become exempt from state regulation by becoming a "qualifying facility" ("QF"). See 18 C.F.R. § 292.602(c); 18 C.F.R. § 292.601(a), (b). Such facilities include all QFs that are a cogeneration facility, a geothermal or biomass small power production facility, or any other small power production facility (including hydroelectric, solar, and wind-power facilities) having a capacity of 30 megawatts (MW) or less. In general, all of the types of renewable energy resources facilities referenced in the bill would be eligible to become a QF. Such a facility can become a QF through a simple self-certification with FERC.

Second, regardless of whether a renewable energy resource facility is exempt as a QF, the facility can also become exempt from RCA certification and regulation through a petition to the Regulatory Commission of Alaska (RCA) that demonstrates that the exemption is "in the public interest." *See* AS 42.05.711(d). In 2009, two small hydroelectric facilities obtained public interest exemptions from the RCA based on the facility's generation source and small size, the fact that the facility would sell power only to an electric utility, and the cost and burden of certification and regulation. *See* RCA Order Nos. U-08-102(2) and U-08-132(2) (attached).

2. The proposed statutory exemption would impair the RCA's ability to ensure that the facility's rates, terms, and conditions of service are just, reasonable, and non-discriminatory, particularly when the facility sells power to multiple electric utilities. Although the RCA would have to approve the purchasing utility's entering into a power purchase agreement with the facility, that so-called "indirect regulation" of the exempt facility would not give the RCA full access to the facility's cost and financial information.

3. The proposed statutory exemption would divest the RCA of jurisdiction to adjudicate complaints by the purchasing electric utility against the facility for failing to provide adequate, non-discriminatory service. In addition, if the facility were regulated and a dispute arose regarding a rate issue or service issue that the facility and the purchasing electric utility did not clearly contemplate in their long-term power purchase agreement, the RCA would have jurisdiction to resolve that dispute. Without RCA jurisdiction, the purchasing electric utility would be limited to filing a lawsuit in court to address those types of issues, which involves significantly more cost and delay (and less adjudicator expertise over the subject matter) than a complaint filed with the RCA.

4. RCA certification of a renewable resources facility imposes an "obligation to serve," which ensures that the facility cannot unreasonably refuse to provide service to a particular customer. The broad exemption proposed under the bill would preclude the RCA from enforcing such an obligation, thus allowing the facility to discriminate among potential power purchasers.

5. If a renewable resources facility is certificated and regulated by the RCA and the facility seeks bankruptcy protection, the RCA generally would have standing in the bankruptcy proceeding to help ensure that the public interest is protected. That measure of protection would not exist if the facility is categorically exempt from RCA jurisdiction by statute. That issue can be significant because a renewable energy resources facility may be (and likely will be) owned by a subsidiary corporation or subsidiary limited liability company in such a way that the

Senator Lesil McGuire

March 8, 2010

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effective, ultimate "owner" of the facility is shielded from all liability for the debts and obligations of the facility. That is one of the reasons that the RCA carefully considers whether the legal owner of a proposed public utility is, in fact, "fit, willing, and able" to provide public utility service when the RCA decides whether to certificate the utility, or when the RCA decides whether to grant a public interest exemption from regulation. Under the broad exemption provided for in the bill, the RCA would lack jurisdiction to review such matters, particularly after the purchasing electric utility obtains RCA approval of the power purchase agreement.

6. The proposed statutory exemption would preclude affected electric utilities from having input regarding whether the exemption of a particular facility is justified. The existing RCA public interest exemption process allows utility input and public input and allows the RCA to determine on a case-by-case basis whether the facts and circumstances justify exemption for a particular facility. Related to that, until a power purchase agreement and the associated rates, terms, and conditions of service are negotiated regarding a particular facility, the utilities that are intended to purchase power from the facility may not have enough information to know whether an exemption from RCA certification and regulation is justified. The broad statutory exemption provided for in the bill would preclude affected electric utilities from making that determination when the facts and circumstances associated with a particular facility are known.

7. There has not been adequate time for APA and its members to fully explore all of the unintended consequences of the type of broad, absolute exemption provided for in the bill.

#### **More Specific Concerns Regarding SB 277:**

1. The bill's 65 MW size restriction appears to be too high. The potential justification for exemption from RCA certification and regulation is very different if the exemption applies to a small 500 kilowatt (kW) renewable resources facility as opposed to a large 65 MW facility.

2. The bill would exempt a facility that sells its output to *any type* of regulated public utility, not just to a regulated *electric* public utility. That would allow the exempt facility to compete against the local electric utility for firm electric sales to non-electric utilities that are within the local electric utility's certificated service area.

3. The bill would exempt a facility that sells its output to *multiple* regulated electric utilities. Sales to multiple electric utilities raise concerns about preventing the facility from discriminating among customers with respect to rates, terms, or conditions of service.

Senator Lesil McGuire

March 8, 2010

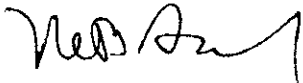
Page 4 of 4

4. The bill would exempt a facility even if it is closely affiliated with a regulated electric utility to which it sells power. That raises additional concerns about the potential for discriminatory preferences among the electric utilities that purchase power from the facility.

5. The bill would exempt cogeneration facilities because "renewable energy resources" under AS 42.45.045(l) include "wasteheat recovery." Electric utilities have had contentious experiences with developers attempting to force the utility into uneconomic power purchases from proposed cogeneration plants.

Again, APA and its members have had only a limited amount of time to attempt to review the potential ramifications and unintended consequences of SB 277. APA and its members will continue their review of the bill and may have other concerns as they review it in greater detail. In the meantime, APA stands ready to discuss its concerns with you or your staff whenever is convenient for you. We suggest you initiate a meeting with all interested parties as soon as possible so that we can have a discussion of all the issues.

Sincerely,



Marilyn Leland  
Executive Director

# ALASKA STATE LEGISLATURE

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Chair  
Senate Special Committee on Energy  
Senate Special Committee on  
World Trade, Technology, and Innovations

Co-Chair  
Senate Resources Committee

Member  
Senate Judiciary Committee  
Joint Armed Services Committee

Senator.Lesil.McGuire@legis.state.ak.us

## SENATOR LESIL MCGUIRE

DATE: March 3, 2010

TO: Senator Hollis French, Chair Senate Judiciary Committee

FR: Senator Lesil McGuire

RE: Request to Schedule SB 277: Public Utility Exemption: Renewable Energy

Dear Senator French,

Please schedule SB 277: Public Utility Exemption: Renewable Energy for a hearing in the Senate Judiciary Committee at your earliest convenience.

Attached is a bill packet that contains the following:

1. Sponsor Statement
2. Current Version of the Bill: CS SB 277 (26-LS1353\P)
3. Identification of Changes
4. Original Version of the Bill: SB 277 (26-LS1353\E)
5. Fiscal Notes:
  - a. DCCED: Zero fiscal note /19/2010
6. Supporting Documents
  - a. Legislative Legal Services: Opinions
  - b. RCA Statutes
  - c. FERC FAQ on Qualifying Facilities
    - i. FERC Regulations on Small Power Generation
  - d. NERA, Economic Consulting Report: *Competitive Electricity Markets: The Benefits for Customers and the Environment*

To Testify:

Ethan Schutt, CIRI

Michael Pawlowski in my office will be the staff contact for this bill. Her number is 465-5159. Please call if you have any questions.