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BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

	) **UM 1182**
In the Matter of	)
NORTHWEST AND INTERMOUNTAIN	) PHASE 1
POWER PRODUCERS COALITION	)
	) REPLY COMMENTS OF THE
Petition for an Investigation Regarding	) NORTHWEST AND INTERMOUNTAIN
Competitive Bidding	) POWER PRODUCERS COALITION
	)

INTRODUCTION

Pursuant to Prehearing Conference Memorandum issued in this case on January 26, 2011, the Northwest and Intermountain Power Producers Coalition ("NIPPC") hereby files its Reply Comments in Phase 1 of this case regarding the Public Utility Commission of Oregon's ("Commission's") request for proposal guidelines ("RFP Guidelines," or "Guidelines"). For the reasons set forth below, NIPPC stands by its Opening Comments and provides response herein to the concerns raised by other parties regarding retention of the Independent Evaluator ("IE") through the final shortlist negotiations. NIPPC also continues to believe that there is no need to lower the 100 megawatt ("MW") cap.

REPLY COMMENTS

A. Because concerns raised by other parties can be adequately addressed, NIPPC urges the Commission to amend the Guidelines to require utilities to retain the IE through the final shortlist bidding negotiations.

As discussed in more detail in NIPPC's Opening Comments, NIPPC submits that the benefits of retaining the IE through the final selection process far outweigh any potential costs. All of the concerns raised by other parties in their Opening Comments can be adequately addressed.

1. The Commission should reject Portland General Electric Company's argument that there is insufficient evidence in the record to support adoption of new Guidelines requiring IE retention through the final negotiations.

The Commission has held multiple RFPs under the 2006 Guidelines, and obviously has reviewed extensive evidence regarding the RFP process upon which it can base a decision to expand the role of the IE through an amendment to the Guidelines. Yet Portland General Electric Company ("PGE") asserts, apparently based on the findings set forth in the 1991 RFP Guidelines in Order No. 91-1383, that to retain the IE would be a "fairly drastic step and can only be taken if it is supported by substantial evidence in the record." *PGE Opening Comments*, at p. 6. To the extent that PGE is objecting to the processing of this case by comments rather than an evidentiary hearing, PGE implicitly consented to the processing of this Phase of the case by comments when it failed to raise such an objection at the procedural hearing on January 26, 2011, and therefore waived this argument. Further, the record contains sufficient evidence supporting retention of the IE.

The Oregon courts "will uphold PUC's order if it discloses a rational relationship between the facts and the legal conclusion reached." *Pacific Northwest Bell Telephone Co. v. Katz,* 116 Or.App. 302, 305, 841 P.2d 652 (Or. App. 1992). "The function of judicial review of PUC orders is not to substitute one view of the facts for another." *Industrial Customers of Northwest Utilities v. Public Utility Commission of Oregon*, 196 Or. App. 46, 55, 100 P.3d 1072 (Or. App. 2004). The order must be supported by substantial evidence, and "[s]ubstantial evidence exists to support a finding of fact when the record, viewed as a whole, would permit a reasonable person to make that finding." O.R.S. 183.482(5)(a)(C); *see also* O.R.S. 756.610.

The Commission's rules of procedure define admissibility of evidence more broadly than the Oregon Rules of Evidence. *See* OAR 860-001-0450. Indeed, the only judicial decision PGE cites contradicts PGE's position. *See Industrial Customers of Northwest Utilities v. Public Utility Commission of Oregon*, 240 Or.App. 147, 166, 246 P.3d 1151 (Or. App. 2010) (affirming Commission ruling that relied on written testimony as "comments" and stating, "Nothing in the record suggests that the PUC would have attributed any different weight to Blumenthal's testimony had it been labeled differently"). The Commission may render its decision based on the comments submitted in this docket.

NIPPC submits that, if the Commission is concerned with PGE's assertion, the Commission may take official notice of the prior filings, documents and orders in the related dockets, including UM 1276 and UM 1066, which led to the reopening of this case in Order No. 11-001. *See* OAR 860-001-0460(1) (a)-(d) (allowing the Commission to take official notice not only of all matters of which the courts of the State of Oregon may take judicial notice, but also reports and administrative rulings of the Commission and other governmental agencies, as well as documents and records in the files of the Commission).[1] The filings in those cases surely provide sufficient evidence to support a finding that the utilities have a resource ownership bias, which would justify the Commission's decision to retain the IE through final negotiations rather than adopt market-based rates or an incentive mechanism. The Commission can also take official notice of the filings and documents in each of the RFP dockets since the 2006 Guidelines. The Commission could note that the RFP in UM 1368 was the only RFP to result in a power purchase agreement ("PPA") with an independent power producer ("IPP") and was one of the only two RFPs the utility to retained the IE through final negotiations.

The Commission could even take official notice of the California Public Utilities Commission's finding that it was reasonable to require IE retention through the entire process "[b]ecause of the complexity, importance, and potential for conflicts and disputes[.]" *See Renewable Northwest Project's Opening Comments* at p. 3 & n.2 (quoting CPUC Decision No. 06-05-039 (May 25, 2006)).

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[1] Taking official notice allows the Commission to make the evidentiary records in those cases part of the record in this case. *See State of Oregon v. Bellah*, Docket No. A140219, A140220 (Or. App., April 13, 2011) (noting that "[t]he trial court took judicial notice of its file and of the [Oregon Judicial Information Network] record of the case and, although the court made no particular findings at the hearing on the motion to dismiss, those documents are part of the evidentiary record on review"). The Oregon courts have long encouraged liberal use of official notice in Commission proceedings on the ground that "[l]aborious proof of what is obvious and notorious is wasteful." *Pierce Auto Freight Lines, Inc. v. Flagg*, 177 Or. 1, 40, 159 P.2d 162 (1945) (internal quotation omitted). The Commission may give notice in its order, and any party may rebut the noticed fact within 15 days. *See* OAR 860-001-460(2).

The Commission may also rely upon a White Paper completed after issuance of the 2006 Guidelines, which NIPPC is submitting into the record as Attachment 1 of these Reply Comments. *See* Susan F. Tierney, Todd Schatzki, Analysis Group, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices* (*hereinafter* "*NARUC RFP White Paper*" or "*NIPPC Reply Attachment 1*") (July 2008). The National Association of Regulatory Commissioners ("NARUC") commissioned this White Paper, as part of its collaborative dialogue with the Federal Energy Regulatory Commission on competitive power procurement policies and practices.

The *NARUC White Paper* studied RFP processes utilized across the country to provide guidance for state utility commissioners. *NIPPC Reply Attachment 1* at p. 13. With regard to the necessity of an IE (which it refers to as an "independent monitor" or "IM"), the *NARUC White Paper*'s Executive Summary states, "Key safeguards to guard against improper self-dealing include: . . . Use of an independent monitor throughout <u>*all phases of the process*</u>[.]" *Id.* at p. 9 (emphasis added). The *NARUC White Paper* also listed "Monitoring contract negotiations" among the possible roles of the IE, and stated:

> By playing these roles, an IM may add substantial benefits, particularly in terms of maintaining process fairness and objectivity to mitigate the potential exercise of improper self-dealing. However, an IM can also improve the efficiency of the process and the quality of the results. For example, the IM can monitor communications to ensure an appropriate level and substance of communications. The IM can assist in ensuring appropriate resolution of technical challenges that inevitably arise in the course of a complex competitive procurement. Similarly, the IM can monitor and report on the utility's conduct and the procurement's competitiveness as a way to help the commission evaluate

> whether the results of the procurement should be approved as consistent with just and reasonable rates. . . .
>
> Against these benefits of including an IM are the costs to the process – especially the cost of hiring the IM, which can be substantial. However, as many states have determined, *the benefits of IMs* seem to outweigh these costs in most instances, and *are a necessary element of a credible process where the utility itself has a financial stake in the outcome of the competitive procurement itself.*
>
> *Id.* at pp. 32-33 (emphasis added).

There is compelling evidence in the record for the Commission to determine that utility resource ownership bias should be addressed by amending the 2006 Guidelines to require retention of the IE through the final negotiations in any RFP including a utility-ownership option.

2. NIPPC agrees that the role of the IE should be well defined, and hereby submits proposed Guidelines defining the IE's new role through final negotiations.

The utilities each appear to assert that the Commission should not amend the Guidelines to retain the IE through the final negotiations because the IE's role is too undefined, and IE retention will therefore lead to uncertainty. *See PGE's Opening Comments*, at pp. 3-5; *PacifiCorp's Opening Comments* at pp. 5-6; *Idaho Power's Opening Comments*, at p. 4. NIPPC agrees that the Guidelines should define the IE's role, and therefore has provided a proposed modification of the 2006 Guidelines as Attachment 2 of these Comments ("*NIPPC Reply Attachment 2*").

Under NIPPC's proposed Guidelines, the utility must retain the IE in any RFP including a utility ownership option among the final short list. That would include any RFP with a benchmark resource or with a build-to-own transfer option still listed among the potential winning resources at the short list selection stage. As discussed in NIPPC's Opening Comments, NIPPC believes that the IE should be retained in RFPs without a utility ownership option, only if the circumstances warrant retention of the IE. Consistent with the *NARUC White Paper* and with the Commission's prior precedent regarding PacifiCorp's retention of the IE in UM 1368 and UM 1429, NIPPC suggests the IE's role should be defined as that of an "independent monitor" during the final negotiations in order to observe and document the tenor, topics and fairness of the final bidding negotiations amongst final bidders with contrast to the utility's treatment of its bid-in benchmark resource or other utility-ownership options.[2] The IE's monitoring role should be guided by its principal objective, i.e., finding the least cost, least risk options for ratepayers.

NIPPC also proposes that the Guidelines provide that the final selected resource(s) should allocate between them and pay the costs of the IE's additional time. The utility's shareholders would be held to the same standard as the other final bidders, which is consistent with the manner in which the RFP Guidelines should be implemented to place the utility on equal footing with IPP bidders.

3. NIPPC's suggestion that the final winning resources in the RFP pay for the IE costs in final negotiations would address concerns regarding increased cost of the RFP to ratepayers.

As described above, NIPPC has proposed that cost-recovery for the IE's services during the final negotiations be passed onto the winning resource(s). *See NIPPC Reply*

[2] This is consistent with PacifiCorp's characterization of how its contract with the IE described the IE's role during final negotiations in UM 1368 and UM 1429. *See PacifiCorp's Opening Comments,* at p. 5 n. 6.

Attachment 2, at p. 1 (Guideline 5). If the Commission adopts NIPPC's suggestion, retention of the IE through final negotiations will not increase costs to the utility's customers, and the concerns raised in other parties' comments will be adequately addressed. *See Commission Staff's Opening Comments*, at p. 3; *PGE's Opening Comments*, at pp. 7-8; *PacifiCorp's Opening Comments*, at pp. 7-8; *Idaho Power's Opening Comments*, at p. 3; *ICNU's Opening Comments*, at pp. 4-5.

4. The purpose of retaining the IE through final negotiations includes providing assurance of fairness to bidders and a deterrent to utility self-dealing, and the Commission should not rely on assertions that the sole benefit is to generate evidence for future utility cost recovery proceedings.

NIPPC's Opening Comments and the Renewable Northwest Project's Opening Comments described the benefits of IE retention in negotiations to include providing assurance of fairness to bidders, a deterrent to utility self-dealing, and even a touch point for the utility and the bidders to ensure the parties that the negotiations are fair. *See NIPPC's Opening Comments*, at pp. 11-12; *Renewable Northwest Project's Opening Comments*, at pp. 3-6. This is consistent with one developer's experience in a California RFP, *see Renewable Northwest Project's Opening Comments*, at p. 4, and with the conclusions of the *NARUC White Paper* cited above. Commission Staff has expressed concern that retention of the IE is not worthwhile because in the two Oregon RFPs in which the IE was retained (UM 1368 and UM 1429), the IE generated no information "that would have much evidentiary value in a subsequent ratemaking proceeding." *See Commission Staff's Opening Comments*, at p. 2. This should not be the sole focus of the Commission, however.

The IE's retention is not intended solely to catch the utility in an improper act of self-dealing or otherwise tilting the acquisition process in favor its benchmark resource; the goal is deter such acts, provide assurance to the IPP community that such acts will not occur, and provide a touch point for fairness during negotiations.[3] That the IE produced no evidence of improper self-dealing in the two PacifiCorp RFPs does not mean that the IE's presence was useless, and rather, it could just as well demonstrate that the IE deterred improper conduct.

5. The IE's extended presence will not unduly hinder negotiations or deter would-be bidders in the RFP, and instead will provide substantial benefits.

The Renewable Northwest Project has provided a telling description of an actual experience with an IE's involvement in a final RFP negotiations, and stated that the IE "can blend into the background and negotiation can proceed normally." *See Renewable Northwest Project's Opening Comments*, at p. 4. In fact, the IE actually improved the negotiation process by providing "reassurance that the negotiating parties were being treated consistently with respect to particular contracting points." *Id.* at p. 4. Commission Staff and the utilities, however, have made some unsupported assertions that

[3] PGE makes the remarkable and indefensible assertion that an IE's presence would have no impact on a utility's conduct in final negotiations "[b]ecause benchmark resources are not part of the negotiations." *See PGE's Opening Comments*, at p. 3. As the comment demonstrates, the incentive to "manage" final negotiations with independent bidders in favor of a utility is obviously present whenever the utility itself has a financial stake in the outcome of the competitive procurement itself, and, if unaddressed, this incentive places a cloud over the fairness of the entire process. *See NIPPC Reply Attachment 1*, at pp. 32-33. To the extent PGE is contemplating an RFP where there is no utility-ownership option, NIPPC's proposed Guidelines would not necessarily require retention of an IE in final negotiations. *See NIPPC Reply Attachment 2*, p. 1 (proposed Guideline 10(f))

the IE could theoretically hinder the negotiation process or otherwise prevent the parties from freely negotiating. *See Commission Staff's Opening Comments*, at p. 3 (stating the "utilities have stated that there may be a perception that the bidder cannot fully disclose information to the IE, or it is reluctant to do so"); *PGE's Opening Comments,* at pp. 4, 6-8; *PacifiCorp's Opening Comments,* at p. 7; *Idaho Power's Opening Comments,* at p. 3. These concerns are unfounded and unsupported.

The utilities have pointed to no independent developers who would abandon an RFP solely because the IE will be present during final negotiations. A confidentiality agreement will protect communications during negotiations, and the IE will aid the process, not hinder it. Simply put, the IE's expanded presence will not defeat the utilities' ability to acquire the best resources. Indeed, both RFPs conducted in Oregon with an IE retained through the final negotiations (UM 1368 and UM 1429) resulted in acquisition of a final resource despite the theoretical, logistical concerns voiced by some parties to this case.

6. Retention of the IE through final negotiations will further the Commission's RFP Goals set forth in the 2006 Guidelines, and even if any single Goal is not directly satisfied the Commission is not bound by the RFP Goals from the 2006 Guidelines.

The Commission set forth five goals in its order adopting the 2006 Guidelines. *See* Order No. 06-446, at p. 2. Strengthening the Guidelines by retaining the IE through final negotiations will clearly help the Commission achieve the first goal to "provide an opportunity to minimize long-term energy costs," and the fifth goal that the Guidelines be "understandable and fair." *Id.* Yet Commission Staff and PGE assert that the goals set forth at the time of the 2006 Guidelines may be frustrated by retaining the IE. *See*

Commission Staff's Opening Comments, at p. 3 (expressing concern regarding the goal to allow the parties to negotiate mutually beneficial agreements); *PGE's Opening Comments*, at pp. 8-10 (citing goals to not impair utility management's prerogative in acquiring resources, to allow parties to negotiate mutually beneficial agreements, and to be understandable and fair). For the reasons discussed above, NIPPC's proposed revisions to the Guidelines would not frustrate any of the five goals set forth at the time of the 2006 Guidelines and presumably still reflective of Commission policy.

Further, even if there were some way to construe one of the 2006 goals as being frustrated, those goals do not bind the Commission at this time. Indeed, at the time the Commission adopted the 2006 Guidelines, it made modifications to its prior goals set forth in the 1991 Guidelines. *See* Order No. 06-446, at p. 2. It did so in order to take "into account the experience we have gained since we adopted the initial guidelines in 1991." *Id.* Likewise, the Commission is now free to use the experience it has gained since 2006 to again revise the Guidelines and, if it deems necessary, the associated RFP goals.

7. The Commission should reject PGE's suggestion that any changes to the Guidelines should be applied only after completion of its three upcoming RFPs to acquire a total of 830 to 1085 megawatts of nameplate, year-round resources.

The Commission's recent precedent of directing retention of the IE through final negotiations in PacifiCorp's 2008 and 2009 Renewable RFPs (UM 1368 and UM 1429) has put all Oregon utilities on notice that the IE may be retained through the final negotiations. Yet PGE asserts, "As a matter of both fairness and efficiency, the Commission should not impose any new requirements on the role of an IE on any competitive bidding process for which an IE has already been selected." *PGE Opening Comments*, at p. 10. In Docket No. UM 1524, the Commission has already selected an IE for PGE's three 2011 RFPs – (1) a capacity RFP with a 200 MW peaking gas plant benchmark, (2) a baseload energy RFP with a 300 to 500 MW gas plant benchmark, and (3) a renewable RFP with a 330 to 385 MW wind farm benchmark. *See PGE's 2009 IRP*, at pp. 203-06, Docket No. LC 48.

PGE initiated that IE selection docket on February 18, 2011, well after the Commission had directed retention of the IE in the PacifiCorp RFPs and after the Commission issued Order No. 11-001, re-opening this docket and expressing interest in considering institutionalizing an expanded the role for the IE. PGE was well aware that the IE may be retained through final negotiations at the time of selection of the IE for its 2011 RFPs. PGE makes no assertion that the IE selected – Accion Group – would be inadequate as a monitor of the final negotiations. The Commission should reject any claim that requiring Accion Group to remain through the upcoming RFPs would be unfair to PGE, and should state that any amendments to the Guidelines will apply to PGE's upcoming RFPs.

B. NIPPC continues to believe that there is no need to lower the 100 MW cap.

Other parties have suggested that the Commission should adopt criteria to define a single project to address problems such as PacifiCorp's development of wind projects sized such that it could avoid proceeding through the Guidelines. NIPPC does not object to a reasonable set of criteria to define a single resource in the context of the Guidelines, but submits that any set of criteria may be subject to manipulation by the utilities. NIPPC therefore still maintains its position in its Opening Comments that the Commission should restate the existence of a heightened burden in rate recovery proceedings for projects designed to side-step the Guidelines. Such a deterrent will be at least as effective as any criteria designed to prevent utilities from gaming the system.

CONCLUSION

For the reasons set forth above and in NIPPC's Opening Comments, NIPPC does not believe it is necessary at this time to reduce the threshold resource size triggering the applicability of the Guidelines below 100 MW. NIPPC respectfully requests, however, that the Commission amend the Guidelines to expressly require that the Independent Evaluator be retained through the final shortlist negotiations. In closing, NIPPC again encourages the Commission to reach a speedy resolution in this Phase of the docket so that an IE may be retained in PGE's upcoming RFPs through the final negotiations.

RESPECTFULLY SUBMITTED this 22nd day of April, 2011.

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Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices

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This White Paper was commissioned by the National Association of Regulatory Utility Commissioners (NARUC), as part of its collaborative dialogue with the Federal Energy Regulatory Commission (FERC) on competitive power procurement policies and practices. This paper represents the views of the authors, and not necessarily the views of NARUC, its members, or the FERC.

COMPETITIVE PROCUREMENT OF RETAIL ELECTRICITY SUPPLY: RECENT TRENDS IN STATE POLICIES AND UTILITY PRACTICES

Over the past two decades, electric distribution utilities[1] have increasingly relied on competitive procurements as a means to obtain power supply for their retail customers. In many states, regulators now rely on such procurements as an important tool to help ensure that utilities provide cost-effective retail services. Today, more than 40 percent of U.S. states (or jurisdictions)[2] have formal regulations or guidance that requires or encourages utilities to use competitive processes. Although the use of competitive procurements to obtain supply for retail customers is not new, many of the requirements affecting when and how competitive procurements are to be used have either been newly enacted or substantively revised in recent years.

With this growing attention on the design and use of competitive procurements, the National Association of Regulatory Utility Commissioners ("NARUC"), in collaboration with the Federal Energy Regulatory Commission ("FERC"), asked Analysis Group to study state and utility policies and practices for competitive procurement of retail electric supply. Focusing on states that have formally adopted policies or guidelines for competitive procurements, we have collected information on current procurement approaches and practices. We have developed criteria for evaluating procurements, reviewed various procurement methods, and identified recent trends in state policies and utility practices. In this paper, we describe "lessons learned" and – where possible – best practices for designing and implementing competitive procurements in different regulatory contexts and industry settings.

Competitive procurements can provide utilities with a way of obtaining electricity supply that has the "best" fit to customers' needs at the "best" possible terms. In principle, competitive procurements accomplish this goal by requiring market participants to compete for the opportunity to provide these services. However, for competitive procurements to fulfill their promise, they must be designed and implemented in a manner that fosters competition among market participants, including potentially the regulated utility and its affiliated companies. To achieve robust competition, procurements should aim to meet certain criteria:

[1] In our report, we use the phrase "utilities" to describe the distribution utility in its role of assuring adequate supplies for retail electricity customers.

[2] States with formal rules or guidance include Arizona, California, Colorado, Connecticut, Delaware, the District of Columbia, Florida, Illinois, Maine, Maryland, Massachusetts, Montana, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Utah, and Washington. Some other states, such as North Carolina, have less-formal policies and/or have case precedent directing utilities to have tested the market if they propose to build a new generating facility.

- ***The procurement process should be fair and objective.*** A fair and objective process can avoid intended or unintended biases that may prevent selection of the "best" alternatives. The integrity of such a process encourages the participation of third-party suppliers by providing them with confidence that their offers will be fairly considered on their merits. To achieve this goal, procurements must include appropriate safeguards to prevent undue preferential treatment of any offers, to ensure that procurements are implemented as designed, and to ensure that unforeseen circumstances are addressed in manner that is fair and fundamentally consistent with the competitive intent of the process.

- ***The procurement should be designed to encourage robust competitive offerings and creative proposals from market participants*.** To encourage a competitive response, market participants need to have: (1) confidence that their offers will be considered fairly and objectively; (2) assurance that their confidential information will be reasonably protected; and (3) access to adequate information about bidder requirements, product specifications, model contract terms, evaluation procedures, and other factors that would affect the resources they choose to offer.

- ***The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors*.** Selecting the "best" offer(s) requires first identifying appropriate evaluation criteria and then evaluating the offers objectively against them. Designing an effective evaluation process is inherently challenging when such evaluations require comparisons of an array of price and non-price factors. In particular, many of these non-price factors are quite complex to quantify and/or qualitative in nature. By contrast, procuring products that meet standardized specifications (such as full requirements service for standard-offer-service customers in states with retail choice) greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone.

- ***The procurement should be conducted in an efficient and timely manner*.** Procurements should avoid unnecessary administrative costs that may discourage market participants, create transaction costs that produce price premiums in supplier offers, and ultimately impose greater costs on ratepayers.

- ***When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response*.** Regulators' own actions can positively – and in some cases, negatively – affect the integrity of a competitive procurement process. Positive signals can arise, for example, by doing what is legally possible to protect the confidentiality of commercially sensitive information submitted through supply offers, by conducting regulatory reviews in a time frame that supports the "best" price terms in offers, and enforcing elements of the procurement design that enhance the overall fairness and objectivity of the process and the integrity of the procurement results.

In practice, the challenges to designing procurements that meet these criteria depend greatly upon the nature of the products being procured. As described in Table 1 and explained more fully in this report, some states and utilities use competitive procurements to obtain new sources of supply to add to the utility's existing portfolio, while others use them to obtain all supply for retail customers. This basic difference has quite distinct implications for the design and implementation of competitive procurement processes.

Table 1

Frameworks for Procurement of Electricity Supply for Retail Customers

Electric Industry Structure	Divestiture of Power Plants	Procurement Framework / Product Solicited	Supply Portfolio Management	State Examples
Traditional	None	Incremental Supply – typically for resources from a specific power plant obtained through requests for proposals ("RFPs")	Utility	CO, GA, LA, OK
Restructured, No Retail Choice	None or Partial	Incremental Supply (via RFP)	Utility	CA, MT
Restructured, with Retail Choice	Full (or near full)	Full Requirements Service ("FRS") (via auctions or RFPs) to provide retail supply for basic service customers	Market	MA, MD, ME, NJ
		Hybrid FRS Frameworks: • Long-term contracts (with FRS procurement) • Utility ownership of generation, with some degree of portfolio management by the utility • Public power authority • Specialized procurements (e.g., renewables or renewable energy credits)	Variously Assigned to Market and to Utility	CT, DE, IL, OH, PA

In states with a more traditional industry structure in which the utility fulfills its service obligations for all retail electricity customers, the utility is responsible for adding new, or "incremental," resources as needed to the utility's existing portfolio of generating assets, purchased power and demand-side resources. Many states with this traditional structure have chosen to issue rules or other policy guidelines that specify when and how utilities should undertake competitive procurements for acquiring incremental resources. These states include Arizona, California, Colorado, Florida, Louisiana, Montana, Oklahoma, Oregon, Utah, and Washington.

Regulators in these traditionally regulated states face a complex array of important issues in the design of effective procurements. Table 2 (at the end of the Executive Summary) lists a series of important topics that regulators must consider when guiding utilities' use of procurements and their overall design ("architecture") and implementation. This list is long, and the choices often involve important tradeoffs, as described in greater detail in this report. Table 3 (also at the end of the Executive Summary) looks at these same issues through a somewhat different lens by identifying a series of key questions for regulators to bear in mind as they consider whether and how competitive procurements are to be used by utilities in identifying incremental supplies for retail customers.

The first key issue for incremental resource procurements is the design of safeguards to prevent potential improper self-dealing by the utility.[3] Because the utility may financially benefit from the selection of its own self-build offer or a proposal from an affiliate, safeguards are necessary to ensure that the process is not improperly tilted toward the selection of such offers. As the report describes, a variety of means are available to provide such safeguards, including:

- Involvement on a third-party independent monitor ("IM") and/or independent evaluator;
- Measures to increase the transparency of the procurement process to market participants and the public;
- Providing potential bidders with detailed information needed to prepare competitive bids;
- Utility codes of conduct[4] to prohibit improper sharing of information that is valuable to utility affiliates in their construction of procurement offers and/or their competitiveness in other electricity markets; and

[3] By using the phrase, "improper self-dealing," we intend to recognize that many states that require or encourage competitive procurements for incremental supply also require – indirectly or directly – that the utility also participate in the process as one of the entities making a supply proposal. This inherently places a utility in the position of being a "competitor" as well as the entity that evaluates and selects the winning proposal. We are characterizing this situation as "proper self-dealing," in the sense that the utility has these two responsibilities, and may, through a fair and objective evaluation, select its own proposal as the winning proposal. By contrast, we use the phrase "improper self-dealing" to indicate situations where the utility acts so as to structure the procurement design, the product to be procured, and the actual evaluation and selection of the winning resource in ways that unduly favor its own proposal or any proposal offered by an affiliate.

[4] In this report, when we use "codes of conduct," we are referring to state policies that guide the character of permissible and impermissible interactions among different staff and divisions of enterprises that include utility companies. We recognize that the FERC has adopted and is considering changes to its own Standards of Conduct for Transmission Providers (see, e.g., 122 FERC ¶ 61,263, Standards of Conduct for Transmission Providers Docket No. RM07-1-000, Notice of Proposed Rulemaking, March 21, 2008).

- Careful disclosure and review of how "non-price" factors are considered and evaluated by the utility in weighing offers from third parties against self-build proposals or affiliate offers. (See further discussion, below.)

The second key issue is the appropriate evaluation of price and non-price criteria. Price criteria typically involve the proposed direct payments for any energy, capacity, environmental credits, or other attributes provided by a resource under contract to the utility. Non-price criteria include the many factors that may also affect how much energy, capacity and other attributes would eventually be supplied by different resources, and their impact on other aspects of the utility's system. Non-price factors can include such things as transmission facility impacts, fuel preferences, location preferences, power plant performance requirements, project development milestones, re-dispatch implications on other resources, credit considerations, utility balance sheet impacts, and the distribution of financial and development risks between the utility and the power provider, and/or the utility and its ratepayers.

Even when a utility does not have an affiliate offer or a self-build proposal in the mix, these non-price factors create unique challenges for evaluating offers. They often introduce complex modeling requirements and the need to weigh factors that may not lend themselves to neat quantitative metrics. Because of these inherent difficulties, use of non-price criteria requires careful regulatory oversight, particularly where the utility has – or perceives it has – a financial interest that varies depending on the outcome of the evaluation process. This oversight is facilitated in such cases through the active involvement of an IM and through other regulatory policies that alter utility incentives (such as commitment to address debt equivalency in rate case proceedings or other mechanisms).

The third issue for procurement of incremental resources is how to structure regulatory policies and practices to promote desirable and competitive supply offers in ways that also fulfill and align with other important regulatory obligations. Commissions may have discretion to decide how and when to review different parts of competitive procurements. Among the things they may directly review and approve are: the type, amount, and timing of resources to be solicited; the RFP documents (including model contracts); and evaluation criteria (including evaluation methods, data and assumptions, credit requirements, and weights among price and non-price criteria). Commissions often have to decide when to examine such things – that is, before the RFP is issued, or after the bids have been received and evaluated by the utility. Providing and clearly demonstrating regulatory support for the approaches being used in the utility's solicitations will help inspire a competitive response. So will early regulatory actions that signal that the Commission will endorse cost-recovery for the outcomes of competitive procurements designed and implemented fairly and objectively by the utility. These signals will reduce market and regulatory uncertainty faced by both utilities and third-party suppliers and will contribute positively to more competitive and less costly incremental supplies for rate payers.

Procurements for all-requirements service introduce different issues and challenges from those described above. In many of the states with retail choice and where distribution utilities now own or control few generation assets (as a result of industry restructuring in the past decade), the utility must obtain needed generation supply for those basic service customers entitled to buy bundled supply from their local utility. In many of these states, the distribution utility uses a competitive procurement process to obtain supply for full-requirements service ("FRS") customers. FRS supply is typically a standardized product and generally includes energy, capacity, ancillary services, and other electricity services needed to meet a slice of the needs of basic service customers as their demand rises and falls over the seasons of the year and the time of day, and as the number of basic service customers changes over time.

States in which utilities have used competitive procurements to elicit offers for FRS supply at some point over the past few years include Connecticut, Delaware, Illinois, Maine, Maryland, Massachusetts, New Jersey, New York, Ohio, and Pennsylvania.

Competitive procurements of FRS supply typically call for offers for the same standardized electricity product (e.g., FRS supply for residential customers). Winners can be selected solely based on the price of their offers. While the technical details of the procurements may require careful design to elicit an efficient and objective result, the "price-only" design greatly reduces other evaluation and regulatory challenges. The elimination of non-price criteria in selecting offers also reduces opportunities for improper self-dealing, which in turn greatly reduces the need to carefully design some other safeguards to protect against such problems.

States using FRS procurements nonetheless face other important challenges. In recent years, for example, regulators in some states have focused efforts on structuring the sequence of procurements to smooth out the effect of potentially volatile prices on rates charged to basic service customers. Most recently, policy makers in some states (e.g., Connecticut, Illinois, and Ohio) are beginning to shift away from sole reliance on FRS procurements, and are developing and considering "hybrid" FRS frameworks that expand or alter the utility's (or other institution's) role in providing supply for retail customers (see Table 1).

Our research indicates that there is now considerable experience in *designing* competitive procurements, although actual experience with procurement *implementation* is somewhat more limited. This is still a "work in progress." Many states are finding competitive procurements to be an essential tool for obtaining electricity supply that nonetheless introduces significant implementation challenges. The ways in which regulators and utilities address the fundamental issues and important details are critical to their success. This report aims to assist regulators in learning from the practical experience of others in using markets to procure electricity supply to help assure just and reasonable rates for retail electricity consumers.

Table 2 Critical Issues in Designing Competitive Procurements for Incremental Supplies	
Commission Choices	**Additional Considerations**
Procurement Process Architecture	
Form of the commission's policy:	What form and in what level of detail will the Commission's policy take: e.g., Regulations? Informal guidelines? Decisions in response to utility proposals?
Role of an integrated resource plan ("IRP"):	What role will an IRP play in determining the timing, amount and type of resources to be procured through a competitive solicitation?
Product definition:	What is the product being procured? Will it be broadly or narrowly defined? Will demand-side offers be considered? How will any policy preferences for particular types of resources (e.g., renewables) be established and implemented?
Procurement procedures:	What requirements will be put in place: e.g., for requests for proposals ("RFPs"), auctions, negotiations, and other design details?
Involvement of an independent monitor:	Under what circumstances will an independent monitor or evaluator be required? Who chooses it? What actions and responsibilities does it undertake?
Commission staff's role:	Will the staff directly oversee the RFP process, on-site with the utility? Will the staff assist the oversight of an independent monitor?
Commission approvals:	At what stage(s) of the process does the Commission carry out a formal review and/or approval? E.g., approval of the IRP? The RFP design? The bidder short-list? Winning offers? Contract approval? Will the Commission's review of the process elements as implemented allow the Commission to endorse the contracts that result from it (assuming a finding that the process produced a competitive result)?
Public participation:	What parts of the process should include public participation? E.g., determination of the types of resources to be procured? Review of RFP instrument and/or model contract?
Scheduling process elements:	How will the timing of the process be designed to balance market and regulatory requirements?
RFP documents:	What materials will be issued with the RFP? E.g., evaluation criteria and weights? Model contracts? Credit and collateral requirements?
Pricing offers:	Will the initial bids involve final offer prices or preliminary indicative offers? Will bidders be permitted to "refresh" their offers over time during the RFP?
Evaluation of Offers	
Evaluation methods and criteria:	How will the array of price and non-price elements (e.g., location, resource operating characteristics, development status) of the offers be evaluated?
Comparison of offers with different risk profiles:	How will the evaluation compare offers with different assignments of various risks (e.g., fuel price risk, fuel supply deliverability, project development, construction cost, availability, credit risk, technology risk, changes in law)?
Transmission impacts and costs of any transmission upgrades:	How will the transmission-related cost implications of different offers be evaluated: Through the status of interconnection requirements? The costs of needed transmission system upgrades? Congestion impacts from dispatch of the proposed offer?
Evaluation of system interactions of offers:	How will the evaluation of offers assess interactions with the rest of the utility's portfolio (e.g., sensitivity analyses of key assumptions, such as fuel price changes)?
Debt equivalency:	Will the process consider the financial impact on the utility of contracts versus rate base investment? If so, how? E.g., using an adder assigned to offers from third parties in the RFP process? As part of the review of the utility's cost of capital in rate cases?

Table 3

Key Procurement Policy Issues – A Checklist for Regulators

	Threshold Question		Second Order Question	Observation:
☑	Should the utility test the market for alternatives to building its own power plants?	➡	If so, does the commission require (formally) the utility to carry out a competitive procurement, encourage such procurements by providing specific guidelines or recommendations, or give the utility full discretion to do so?	Clarifying commission policy toward competitive procurement and making such policy statements easy to find in PUC websites may lower barriers to entry for independent suppliers seeking to participate in the state's market; on balance, this may serve to support a deeper response to any solicitations.
☑	What is the "product" that the utility should procure through competitive solicitations?	➡	Is the procurement designed to solicit narrowly or broadly defined products? That is, should the procurement solicit offers for any type of resources to meet given power supply needs, or limit offers to: o Supply-side resources? o Resources using a particular technology (e.g., renewables) or particular fuel (e.g., coal)? o Resources providing a particular function in a supply portfolio (e.g., baseload v. peaking)? o Capacity resources? o Resources in a particular zone? o Resources from new facilities? o Products satisfying particular regulatory requirements (e.g., renewable energy credits)?	Procurements with more narrowly defined products will allow greater reliance on price and less reliance on other evaluative criteria, although it may limit the depth of the market response and the creativity of offers from market participants. The greater control the commission wishes to exert over the choice of attributes of the product being solicited (e.g., type of resource, location, fuel or technology type, function in the portfolio), the more the commission will likely need to encourage review of formal (or informal) utility long-range resource plans in advance of the resource procurement.
☑	Does the commission want to allow – or require – the utility to participate in the solicitation, either directly as a supplier proposing a resource relying upon regulated investment, or indirectly through a competitive affiliate?	➡	If so, what safeguards will the commission establish and enforce in order to prevent improper self-dealing to assure a fair and competitive solicitation, increase the opportunity for the best resource to be selected, and assure the market that there will be no improper preferential treatment of utility or affiliate offers (thus instilling confidence in the overall design of the competitive procurement)? ➡ Whether or not the utility is allowed to or does participate in the solicitation, how will the commission ensure that the utility's evaluation is focused on decisions supporting lowest-cost, reliable service to customers, even where different resource choices may have different impacts on the utility's own real or perceived financial interests? For example, o Implications for the utility's risk profile, capital costs, balance sheet, and so forth, associated with of a third-party contract versus investment a utility owned plant? o Implications for the performance of the utility's own plants (e.g., implications for stranded investment) from transmission congestion due to new resource additions? ➡ What guidance will the commission provide to the utility and to market participants about how various risks should be assigned in contracts between: o The utility (as buyer) and a third party supplier, and in turn between the utility and its retail customers; o The utility as a power plant owner and its customers.	Putting in place appropriate safeguards to ensure that the utility's decisions are made with the interests of customer benefits and costs in mind involves great care in the overall design, implementation and supervision of the procurement. Key safeguards to guard against improper self-dealing include: ▪ Use of an independent monitor throughout all phases of the process; ▪ Commission review of product definition, evaluation assumptions and techniques, contract terms and conditions, debt-equivalency issues in rate cases (not RFPs) and other elements to support fairness for market participants; ▪ Requiring comparable forms of risk mitigation in utility and non-utility offers, such as comparable treatment of offer "refreshing" and various types of risk, including development and construction risk, power plant performance risk, fuel price risk, and risks tied to changes in law or regulation, such as costs of mitigating carbon emissions.

		Table 3 (Continued)		
	Threshold Question		**Second Order Question**	**Observation:**
☑	To what extent will winning resources be selected on price terms and non-price character-istics, some of which may be difficult to quantify and compare?	➡	How will the commission's policies shape how and what types of non-price characteristics should be considered by the utility in evaluating offers, in light of such criteria as: o The potential differences in the importance of various non-price characteristics in alternative offers; o The potential for evaluation of non-price characteristics to impose high administrative costs or slow evaluation procedures; o The potential introduction of subjectivity (with the opportunity for self-dealing) that non-price characteristics may create? ➡ If non-price factors are necessary to the selection of "best" resources, how will the commission encourage a process that provides sufficient information to the market (e.g., what factors matter, what weight will be assigned to them, and how they will be measured) without also limiting the utility's flexibility to use qualitative judgment in evaluating offers? For example, o Where the winning offers will become part of the utility's resource mix and have network service, how will the need for transmission additions be evaluated, particularly if impacts differ substantially among offers and take time and other resources to fully evaluate? o How will the utility take into account the development status (e.g., types of permits in hand, construction completed) of resource options in ways that support competitive responses while fully accounting for significant differences in risks to consumers? o How will the process incorporate any non-price factors that are relatively easy to put into dollar terms (e.g., transmission enhancement costs), and those (such as project development risk) which are harder to monetize?	The more transparent the evaluation procedures and criteria are to market participants, the more likely they will be assured that the evaluation process will be fair and objective. At the same time, the more the choice of "best resource" depends upon each offer's interaction with the rest of the utility's portfolio, the more the selection will depend upon complex modeling of the utility's portfolio; reliance on these models raises traditional transparency issues associated with "black box" modeling. As a result, regulators will need to pay attention to the modeling assumptions and inputs used by the utility in evaluating resource options (including sensitivity analyses) to help ensure a competitive result. Such review is particularly important where the utility (directly or indirectly) has a financial interest in the outcome of the results (e.g., either directly, if proposing a competing project, or more indirectly, if it owns another existing plant that may become less valuable depending on facility selection).
☑	If you have committed to having your regulated utilities use competitive procurement processes, are you willing to align your own regulatory practices to support them?	➡	Assuming that markets assign risk to uncertain regulatory outcomes, how will the commission arrange – and commit to implementing and enforcing – its own actions to support outcomes that appropriately balance risks between suppliers, the utility and ratepayers? Relevant regulatory risks that can show up in price premiums include: o Uncertainty about cost-recovery for utilities' contracts with power suppliers versus the utility's own investment; o Uncertainty about how long contract approval will take; o Uncertainty about whether the regulator will enforce the rules requiring fairness and objective processes; o Uncertainty about whether the commission will reopen the process – or throw out the results – if it doesn't like the particular outcome of a solicitation; and o Uncertainty about whether the regulator will allow the utility to take actions that circumvent the procurement, alter procurement procedures mid-stream, or dissolve the procurement (irrespective of rationale)?	The higher the market's confidence that the regulatory agency will support its own past policies and decisions, the lower the risk premium that will be built into offers from the market. Past commission policies and decisions may include meeting certain procedural time requirements to which it has committed and enforcing as appropriate any procurement rules previously adopted.

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I. INTRODUCTION AND BACKGROUND

Competitive procurements are not new to the electric industry. Over the past two decades, regulators and the electric distribution utilities ("utilities" [5]) they supervise have experimented with various forms of competitive process as a way to assure lowest-cost, reliable supply for retail electricity customers. In response, the industry has grown to include a wide array of competitive suppliers interested in and capable of providing utilities with power supplies to meet retail customers needs.

Despite this long experience, the use and regulation of competitive procurements has undergone important changes in recent years. Today, many states require[6] – directly or indirectly – that their utilities use competitive procurements as a means of obtaining supplies to serve their retail customers. All told, more than 40 percent of the U.S. states (or jurisdictions)[7] have formal regulations or guidance that requires or encourages utilities to use competitive processes.

In some states with restructured electric industries where the utility no longer owns or controls its own generating resources, utilities are required to procure all of their supply for retail customer's power through competitive processes. Many states with a more traditional industry structure require or at least encourage their utilities to test the market to determine what new source of supply offers the "best" option for meeting incremental customer requirements. In such procurements, the utility's own investment in a new generating resource may compete against offers from third-party power suppliers or the utility's own affiliate. While competitive procurement processes are not new, states in recent years have increased requirements on utilities for when and how such procurements must be undertaken.

With this growing interest in the design and use of competitive procurements, the members of the National Association of Regulatory Utility Commissioners ("NARUC"), through its Committee on Electricity, have been engaged in a collaborative dialogue with the Federal Energy Regulatory Commission ("FERC") on issues related to competitive

[5] Unless otherwise stated, we use the term "utility" to refer to the local distribution utility with certain obligations to serve retail electricity customers.

[6] We note that our use of the word "require" may encompass directives that are a part of non-binding, legislative or commission "guidelines".

[7] States or jurisdictions with formal rules or guidance include Arizona, California, Colorado, Connecticut, Delaware, the District of Columbia, Florida, Illinois, Maine, Maryland, Massachusetts, Montana, New Jersey, New York, Ohio, Oklahoma, Oregon, Pennsylvania, Utah, and Washington. Some other states, such as North Carolina, have less-formal policies and/or have case precedent directing utilities to have tested the market if they propose to build a new generating station.

power procurement. As part of this collaborative dialogue, NARUC engaged Analysis Group[8] to perform a study of competitive procurement of retail electric supply.[9]

This report provides the findings from our study. In the sections below, we:

- Identify key state policy and technical issues associated with current competitive procurement practices;
- Develop criteria for evaluating the success of procurement policies and practices;
- Evaluate current state procurement policies and practices against such criteria;
- Develop guidance on and tradeoffs between "model" competitive procurement practices that are appropriate in different contexts that reflect these criteria; and
- Where possible, identify best practices in procurement design and implementation.

Our findings are intended to provide guidance for states as they determine the appropriate role of and regulations affecting competitive procurements. We do not include any specific recommendations for what any individual state should do with respect to competitive procurements.

To accomplish these goals, we have collected and assembled information on the design and implementation of utility supply procurements. We have researched current state policies that influence whether and how these procurements occur. This information provides many examples of policy designs and practical experiences that have taken shape over many years under different regulatory traditions and industry settings. An important part of our information collection was a survey of state utility commissions that requested detailed information about competitive procurements. Responses to that survey, along with our own research and information collection, identified many key relevant documents, including:

- State legislation;
- Commission orders related to general procurement policy and to individual utility procurements;
- Utility request for proposals ("RFPs");
- Independent monitor ("IM") reports;

[8] The study has been conducted by Analysis Group's team: Susan Tierney, Ph.D., Managing Principal; Todd Schatzki, Ph.D., Manager; Andrea Okie, Associate; Pavel Gavrilov, Senior Analyst; and Mary DiMatteo, Analyst.

[9] NARUC, "Request for Proposal to Identify Model State and Utility Practices for Competitive Procurement of Retail Electric Supply," Proposal Number 000-07-01, September 26, 2007.

- Regulatory filings by various stakeholders (including electricity suppliers); and
- Other relevant documents.

The body of documents we have collected through this process is available electronically for access by the public.[10]

Our review focuses primarily upon activities in states that have formal requirements or guidelines for competitive procurements.[11] Specifically, we do not review the relevant competitive procurement policies or practices of publicly-owned utilities (e.g., municipally owned utilities and cooperatives), small investor-owned utilities, or unregulated competitive retail suppliers in states with retail competition (e.g., Texas). Additionally there are a number of other things which we explicitly did not study, based on our understanding of the original scope of work from NARUC.[12] Notably, our analysis is confined to a review of competitive procurements as regulated by state public utility commissions.[13]

[10] Documents are available at: <http://procurement.webexworkspace.com/>. Members of the public may access these documents by registering as a "guest" at this website.

[11] Many utilities in states without formal policies on procurement may undertake competitive procurements as a part of, for example, demonstrations that certain resources (such as those, for which the utility is seeking certification and cost recovery), are least-cost.

[12] We do not make recommendations about whether states should or should not rely on competitive procurements. Nor do we prescribe a "correct" approach to be adopted across all states that decide to use competitive procurements. We believe that this is entirely a matter of state policy preference, and in some cases, legislative authority. Also, because use of competitive procurements and their design involves a number of important trade-offs that affect how risks are assigned between utilities and their customers, on the one hand, and utilities and their suppliers, on the other, we do not conclude that one or another trade-off is right or wrong. In some cases, we attempt to elucidate implications of trade-offs between particular approaches. We refrain from critiquing particular states' approaches by name; instead, we focus on issues in procurements that are relevant for states in designing or refining competitive approaches in their states. We do not specifically cover competitive procurement practices in prior periods that are no longer being used in states (e.g., for PURPA implementation). We do not focus on competitive procurement for supplies of relatively short-term length (e.g., less than one year). We do not focus on policy the details for states with open dockets on whether to modify their current approaches to procurements. And, in situations where prior problems have been addressed in subsequent policy or other regulatory decisions, we have not dwelt on the prior problems.

[13] As requested in the original scope of work, we do not directly review the relationship between: (a) states' policies for competitive procurements and the practices of their distribution utilities, and (b) other policies of the FERC, the states or regional entities throughout the United States.

II. OVERVIEW OF STATE COMPETITIVE PROCUREMENTS

While utility competitive procurement practices vary in many important details across the states, certain common frameworks have arisen. Table 4 describes some of these patterns. It shows, in the middle column, that utilities generally utilize one of two types of procurement frameworks: (a) procurement of “incremental supply,” or (b) procurement of “supply for full-requirements service.” The common approaches result primarily from patterns of regulatory and market conditions that have influenced the types of resources, or electricity products, that regulated distribution utilities need to procure. Table 4 shows different circumstances under which utilities are required (or strongly encouraged) to make use of competitive procurement processes to obtain power supplies for their retail customers.

Table 4

Frameworks for Procurement of Electricity Supply for Retail Customers

Electric Industry Structure	Divestiture of Power Plants	Procurement Framework / Product Solicited	Supply Portfolio Management	State Examples
Traditional	None	Incremental Supply – typically for resources from a specific power plant obtained through requests for proposals (“RFPs”)	Utility	CO, GA, LA, OK
Restructured, No Retail Choice	None or Partial	Incremental Supply (via RFP)	Utility	CA, MT
Restructured, Retail Choice	Full (or near full)	Full Requirements Service (“FRS”) (via auctions or RFPs)	Market	MA, MD, ME, NJ
		Hybrid FRS Frameworks: • Long-term contracts (with FRS procurement) • Utility ownership of generation, with some degree of portfolio management by the utility • Public power authority • Specialized procurements (e.g., renewables or renewable energy credits)	Variously Assigned to Market and to Utility	CT, DE, IL, OH, PA

In a procurement for “incremental supply,” a utility seeks to add a new supply source to its existing portfolio of supply arrangements. This existing portfolio generally includes significant ownership (or control) of generation facilities, but may also include purchase power agreements (short-term or long-term), financial hedges, demand-management, and other forms of resources and supply commitments. This type of procurement is the typical approach used in states with a traditional industry structure, where the utility has the obligation to serve retail customers in its franchise area.

Some traditionally structured states (such as Colorado, Georgia, Louisiana, and Oklahoma) have adopted relatively explicit regulations or formal guidance addressing when and how utilities are to use competitive procurements as part of identifying their next resource additions. Other state commissions do not have codified procurement regulations, *per se.* Some, such as North Carolina, have issued various decisions in the past that have the effect of imposing a presumption that utilities will "test the market" for attractive resource offers at least as a means of demonstrating that their plans (including any proposals to build their own power plants) are economical. Other traditionally structured states do not have policies related to utilities' use of competitive procurements.

Incremental supply procurements are also used in some states (like California and Montana) where utilities divested much of their generating assets under electric industry restructuring, but where retail competition has been suspended. Utilities in these states, as well as in Arizona, currently use incremental procurements to meet resource needs above and beyond the supplies provided by long-term contracts and/or their remaining generating resources.

The other type of procurement is for supply for "full requirements service" (or, a "FRS" procurement). This type is used mostly in states where: (a) retail customers have the right to choose their electricity supplier, (b) distribution utilities have divested all or nearly all of their generation assets as part of electric industry restructuring, and (c) the utility still retains obligations to serve basic service (or default service) customers. Under FRS procurements, the distribution utility obtains all (or most) electricity supply for its basic-service customers (or a particular class of customers). Because these utilities lack their own generation resources but still retain certain service obligations to customers, the utilities' competitive procurements essentially shift much of the responsibility for assembling and managing an array of electricity services to suppliers who are willing to provide needed electricity services for these retail customers.[14]

In a few states with retail competition (e.g., New York, New Hampshire), utilities retain portfolio management responsibilities and functions for basic service customers, similar to the way in which vertically integrated utilities manage a portfolio of assets in states without retail competition. The portfolio of assets managed by these utilities may include generation facility ownership, long-term supply contracts, financial hedges, spot market purchases, and other agreements.[15] While state commissions typically oversee these portfolios for purposes of cost recovery, regulators generally do not direct or

[14] In Maine, electric distribution utilities are not involved in the procurement of supply for FRS customers. Instead, FRS procurements are run by the Maine Public Utility Commission, and winning bidders become the retail providers for customers.

[15] For example, certain utilities in New York and New Hampshire manage supply portfolios, which may include long-term contracts arising from industry restructuring. Utilities recover the costs of these portfolios through rates approved by regulators. Competitive retail providers also generally rely on development of supply portfolios to supply power for their customers. The amount of supply provided through such retail providers varies from state -to -state. In Texas, where there is no "standard offer" service provider, all retail providers procure supply through these unregulated portfolios.

investigate the specific resources utilities arrange as part of the individual components of these portfolios.[16]

In recent years, some states have introduced or are considering adopting policies that create a hybrid framework, in which utilities (or other regulated entities) may consider developing certain types of long-term supply arrangements in addition to the on-going use of FRS contracts for its retail customers. These modifications include requirements (or incentives) for utilities to enter into long-run supply contracts (e.g., New York), utility development and/or ownership of generation facilities (e.g., in Connecticut, Ohio), and development of state power authorities (e.g., in Illinois).[17]

Incremental supply procurements and FRS procurements differ in an important, fundamental way. FRS supply procurements are typically designed as *price-only* procurements, in which the utility requests bids to supply a uniform product using a standard contract. By standardizing product specifications and contract terms, price is the only factor differentiating alternative offers and suppliers offering the lowest prices are selected as the winning bidders. In contrast, offers submitted in response to incremental supply procurements *differ along multiple dimensions*, including price and non-price factors. To select the "best" offer, the utility not only must evaluate and compare each offer's unique attributes, but must also evaluate how each possible new resource would interact with the rest of the utility's overall supply portfolio. This significantly complicates the evaluation and selection process.

As a result of these procurement characteristics, price-only auctions for FRS supply are similar to on-line shopping for a mass market product (such as a specific book or a particular toy) that a consumer has already decided to purchase.[18] In contrast, incremental supply procurements are more akin to buying a house, because no two houses are alike and the choice among houses requires comparison of the many different attributes that differ between houses. Because of this fundamental difference in these two approaches, we discuss each of these approaches separately below. Before doing so, though, we describe various criteria to use in evaluating procurement processes.

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[16] Our assessment does not focus on the development of these portfolios, although lessons from incremental supply procurements may provide some guidance for best practices for and oversight of procurement of individual components of such portfolios.

[17] Additionally, Massachusetts has just passed a law (the Green Communities Act, signed on July 2, 2008) that will require utilities to rely on all cost-effective energy efficiency and allow utilities to enter into certain long-term contracts for renewable energy, while also retaining the basic FRS framework.

[18] Bidder eligibility requirements are also similar to the types of minimum standards for merchant quality (e.g., merchant ratings) that people use when considering on-line purchases.

III. CRITERIA FOR THE EVALUATION OF COMPETITIVE PROCUREMENTS

In the end, the goal of using competitive procurements is to enhance the process of identifying and securing resources that "best" meet customers' electricity requirements on the "best" possible terms. With this is mind, we describe the types of criteria that help to distinguish well-designed versus poorly designed competitive procurement processes. We offer five key criteria (listed in Table 5). While each is important and seemingly obvious, together they can pose difficult trade-offs as regulators and utilities design procurements to fit the needs of particular situations. Any commission that decides to rely on competitive procurement processes should use criteria similar to these to guide the design and implementation of such procurements.

Table 5

Criteria for evaluating competitive procurements for retail supply:

Where regulators have committed to relying upon competitive procurement approaches as a means to help identify the "best" resources needed to meet the needs of the utility's customers, the process should have and be viewed as being:

- Fair and objective;
- Encouraging of a robust competitive response and creative proposals from market participants;
- Based on appropriate and relevant evaluation of price and non-price factors;
- Efficient and timely in offer selection;
- Positively supported by regulatory actions that reinforce the commission's commitment to the other criteria.

- ***The procurement process should be fair and objective.*** A fair and objective process will help to ensure that the outcome of a procurement "best" satisfies retail customers' supply requirements and does not reflect any undue preferential treatment of particular bidders. Such a process also promotes participation by assuring market participants that their offers will be fairly considered on their merits. To achieve this goal, procurements must include appropriate safeguards built into the design of the procurement to prevent undue preferential treatment of any offers. These safeguards must be supported through the practical elements of the implementation phase so that unforeseen circumstances are addressed in manner that is fair and consistent with a competitive outcome. The fairness and integrity of a procurement process is affected not only by the actions of the utility, but also by regulatory oversight of the procurement process. If a commission decides to rely on competitive processes, it own actions to enforce fundamental fairness objectives and uphold any prior commitments to use markets are a critical component of the process of identifying the "best" retail supply for utility customers.

- ***The procurement should be designed to encourage a robust competitive response and creative offerings from market participants.*** In developing a competitive procurement, the regulators' goal is to design and carry out a process in which suppliers of the most cost-effective resources not only participate but also submit their most competitive offers. Several conditions are key to encouraging such participation. First, market participants must perceive that their offers will be considered fairly and objectively. Concerns about preferential treatment will lower market participants' willingness to incur the up-front costs necessary to submit offers. Second, procurements must protect confidential and commercially sensitive information submitted by market participants. Third, market participants must have access to adequate information about bidder requirements, product specifications, model contract terms, evaluation and selection procedures and criteria, and other factors that would affect the resources they choose to offer. Finally, procurements should allow sufficient creativity to solicit the best offer for customers.

- ***The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors.*** Selecting the "best" offer(s) requires first identifying appropriate evaluation criteria and then evaluating the offers objectively against them. Designing an effective evaluation process is inherently challenging when such evaluations require comparisons of an array of price and non-price factors. In particular, many of these non-price factors are quite complex to quantify and/or qualitative in nature. By contrast, procuring products that meet standardized specifications (such as full requirements service for standard-offer-service customers) greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone. Identifying evaluation criteria that reflect the attributes of greatest importance will increases the likelihood of eliciting offers that best suit retail customers' supply needs.

- ***The procurement should be conducted in an efficient and timely manner.*** Competitive procurements should avoid unnecessary administrative and procedural costs that may discourage market participants and ultimately impose greater costs on ratepayers. Because bidders are generally required to honor the terms of their offers once made, an unnecessarily slow process increases the financial risks they face from unanticipated changes in market conditions that occur while their offers are "open." Design of bid submission requirements, evaluation and selection procedures, and the timing of commission review should aim to minimize transaction costs for utilities and/or bidders (and the price premiums they include in their bids).

- ***When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.*** Regulators' own actions can positively – and in some cases, negatively – affect the integrity and outcomes of a procurement process. Positive signals can arise, for example, by doing what is legally possible to protect the confidentiality of commercially sensitive information submitted through supply offers, by conducting regulatory reviews in a time frame that supports the "best" price terms in offers, and enforcing elements of the procurement design that enhance the overall fairness and objectivity of the process and the integrity of the procurement results.

As may be evident, there are potentially important interrelationships among these criteria. Establishing a fair and objective process provides suppliers with confidence that their up-front investment in submitting bids is worth the effort. A fair and objective process will provide regulators with greater confidence that procurements will result in just and reasonable rates, thereby allowing them to provide greater assurance of cost recovery of winning proposals. All else equal, regulators' actions to support the integrity of a competitive process will provide confidence that the process will be fair and objective; this in turn will increase the likelihood that there will be a competitive response from the market and that the winner of the process will be the "best" resource for customers.

VI. PROCUREMENT OF INCREMENTAL RESOURCES

A. OVERVIEW

Incremental resource procurements are used by electric distribution utilities to obtain new resources to add to their existing portfolio of assets, supply contracts and demand-side programs to meet the utility's service obligations to its retail customers. This type of procurement is the basic form relied upon in states with more traditional electric industry structures where the state requires a market test for new resources. In addition, incremental resource procurements are used in states with retail competition where distribution utilities are procuring long-term resources in addition to FRS supplies (e.g., Connecticut) or where utilities serve their basic-service offer customers using a portfolio of resources they manage (e.g., New York).

In states with a more traditional industry structure, utilities provide bundled electricity service as the sole option for retail customers. The utility has the responsibility to manage a resource portfolio, which typically[19] includes large amounts of generation assets under its ownership, but may also include short- and long-term purchase power agreements, demand-management resources, and other forms of financial hedges and supplies. The extent to which these utilities actually use competitive procurements when seeking to identify and secure the next new resource(s) to add to the resource portfolio varies across and within states.

The design of these incremental supply procurements is shaped by several key factors. First, the array of potential resources available to fill a utility's incremental needs varies along many dimensions. Among others, key differences include:

- the physical characteristics of the resources used to provide supply (e.g., location; technology type; fuel type; availability factors; start-up, ramp rates and cycling features; maintenance requirements);

- operational commitments (e.g., dispatchability or non-dispatchability; provision of energy, capacity, ancillary services, or environmental attributes; plant operation, management and fuel provision by the utility under a "tolling agreement"); and

- development status (e.g., site control; environmental permits; interconnection studies; financing; construction).

Offers also differ in the contract structure that will define the:

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[19] Note that we previously described that our report focuses on investor-owned electric utilities; specifically, we do not review the competitive procurement policies or practices of publicly owned utilities (e.g., municipally owned utilities and cooperatives), small investor-owned utilities, or unregulated competitive retail suppliers in states with retail competition (e.g., Texas).

- structure of payments (e.g., all-in prices versus separate payments for such things as energy, capacity, ancillary services; fixed prices versus indexed prices; allowances for payment adders in the event of changed circumstances; penalties and bonuses for certain performance targets (such as delay in meeting development milestones or availability targets);

- the service provided (e.g., energy; capacity; unit dispatch control, in which the utility has control over when the resource delivers power; tolling agreements, in which the utility operates and manages the plant and controls the fuel supply as well; extra compensation for "regulation" service, allowing the output of the plant to be controlled by the system control area operator or system dispatcher; provision of "environmental attributes" such as renewable credits);

- supplier obligations, such as purchase requirements (e.g., minimum quantities of energy over a specified time period, or take-or-pay provisions) and fuel cost requirements (e.g., e.g., tolling agreements in which the utility provides the fuel, or the supplier has responsibility for fuel); and

- the resulting allocation of risks borne by suppliers and utilities.

Assessing the implications of these various contract structures is inherently complex due to an array of important technical details. How a specific power purchase agreement ("PPA") associated with an RFP addresses many of these details has important implications for the types and prices of offers submitted in response to an RFP. If these technical issues and risk allocations are different than those that would arise in a utility self-build proposal, then there will be difficult apples-to-oranges comparison of the offers. That said, a utility self-build proposal could be designed to reflect comparable contract terms (e.g., through price, schedule and other performance conditions as might be contained in a utility contract for engineering, procurement, and construction services (i.e., an "EPC" contract). For these reasons, model contract terms matter, in ways that warrant careful attention by regulators.

While it is possible to design a procurement to elicit offers for comparable products through detailed specification of fuel, technology type, project size, and contract terms, many procurements are designed to leave such important details to the discretion of bidders. As a result, procurements typically involve both price and non-price factors which introduce complexity into comparisons between offers.[20] This complexity makes it challenging, to say the least, to design and implement an overall competitive procurement architecture and the details of its evaluation process in ways that: (a) treat all offers fairly and objectively, (b) arrive at selections efficiently and rigorously, (c) provide enough transparency to be credible without revealing commercially sensitive

[20] Even when there are clear metrics relating to the price terms for an offer, there are often "non-price" issues (both monetized and non-monetized) associated with, among other things, how a proposed resource interacts with the rest of the utility's portfolio in a simulated dispatch and how risks are assigned to the buyer and seller.

business information, and (d) allow the utility sufficient flexibility to respond to potentially innovative and creative solutions from the marketplace. This complexity means that commissions that commit to rely on competitive procurements must be sensitive to these trade-offs.

Second, and perhaps because of the complexity of these trade-offs, incremental resource procurements that include utility self-build (and rate-based) proposals and/or proposals from the utility's affiliates inevitably pose special regulatory challenges to assure that the process is designed and implemented to be fair and objective. Because the utility's (and/or its parent's) financial interests may not be aligned with those of its customers when the utility selects from among the options, extra care is needed to prevent improper self-dealing by the utility. Best practices under these circumstances require a higher degree of regulatory supervision and scrutiny, such as the use of an independent monitor tasked to be the eyes and ears of the regulator and to help bolster the procurement's fundamental fairness and objectivity.

By using the phrase, "improper self-dealing," we intend to recognize that many states that require or encourage competitive procurements for incremental supply also require – indirectly or directly – that the utility participate in the process as one of the entities making a supply proposal. This inherently places a utility in the position of being a "competitor" as well as the entity who determines the "winning proposal." We are characterizing this situation as "proper self-dealing," in the sense that the utility has these two responsibilities, and may, through a fair and objective evaluation, select its own proposal as the "winning proposal." By contrast, we use the phrase "improper self-dealing" to indicate situations where the utility acts so as to structure the procurement design, the product to be procured, and the actual selection of the winning resource in ways that unduly favor its own proposal or any proposal offered by an affiliate of the utility.

Finally, when designing procurement processes to account for both the complexity of evaluating alternative offers and the need for regulatory oversight, it is important to make such choices in light of two other factors involving administrative efficiency. First, it is important to keep the costs to administer procurements relatively low for the bidders and the utility. Second, all else equal, it is important to minimize the time between the submission of offers, development of short-lists of preferred offers, and final selections. Because bidders may be constrained from offering their resources into other markets while their offers are being considered and they may need to maintain firm price terms in spite of market changes, delays in these evaluation stages can increase bidder's opportunity costs to participating in the procurement.

The following sections provide further details on how states and utilities active in competitive solicitations have managed these various trade-offs in the design and implementation of competitive procurements. Our assessment starts with a review of recent policies addressing procurement design, then describes the key components in procurement process architecture, and finally provides a more detailed discussion of key issues relating to the procedures and methods for evaluating offers.

B. RECENT STATE POLICIES ADDRESSING DESIGN OF COMPETITIVE PROCUREMENTS

In recent years, legislatures and regulators in many states have taken steps to either require or amend requirements for when and how utilities should undertake competitive procurements when satisfying resource needs. Table 6 below lists some of these recent policy actions. The recent spate of legislative and regulatory changes suggests that requirements and guidelines for incremental resource procurements may continue to evolve in coming years. Therefore, regulators, utilities and market participants interested in following the progress of such procurement experience will need to continue to track relevant changes. That said, actual procurements tend to occur relatively infrequently, so the evolution may occur at a relatively measured pace.

C. PROCUREMENT PROCESS ARCHITECTURE

1. *Introduction to Procurement Design*

When designing an overall procurement process to be used by utilities in their state, regulators must consider a number of design ("architecture") elements. Specifically, the elements should address not only the procurement criteria previously identified in Section III, but also a number of practical issues. These practical issues include such things as the responsibilities of different parties, the rules governing communications between various parties, and the materials and information that must be developed and made available to various parties. Designing such an overall procurement framework addressing all of these elements involves a number of important tradeoffs.

First, the process must be designed to ensure that winning bids are chosen based on a fair and objective process. In particular, the process must be structured to avoid improper self-dealing should the utility or its unregulated affiliates be required or allowed to offer a proposal in the procurement. Many elements of the overall design of the procurement process can mitigate the utility's ability to improperly bias the outcome of a procurement. These include:

- Commission review of RFP instruments (including what electricity supply products should be procured) and oversight of RFP procedures;
- Codes of conduct regarding interactions between utility personnel involved in evaluating offers and (a) personnel involved with developing cost projections and other elements associated with the utility's self-build proposal, and (b) any personnel of its unregulated generation affiliate;
- Engagement of an independent monitor ("IM") with reporting responsibilities to the regulatory commission and a clear scope of work with regard to procurement design, implementation, oversight, and reporting;

- Public participation in procurement design, and in commenting on draft RFP instruments, including key evaluation assumptions and model contract terms;
- Information requirements for RFP instruments (e.g., product specification, evaluation criteria, etc.), and reporting of evaluation process and results; and
- Means to control various utility personnel's access to bidders' commercially sensitive information, including information shared by utility senior managers with responsibility for both self-build offers and procurements from the market.

Table 6
Recent Changes in State Policy Requirements Involving Competitive Procurements for Incremental Resources

State	Date	Docket Name	Description
AZ	2007	Recommended Best Practices for Procurement (ACC Decision No. 70032)	Commission adoption of "Best Practices" for procurements that identify acceptable procurement methods, and circumstances when RFPs and independent monitor should be used [1]
CA	2003 - present	Energy Action Plan, PUC Decision 04-01-050, AB57 and various other rulings	A series of legislative and commission decisions have established procedures by which utilities develop long-term procurement plans and implement resource procurements.
FL	2002	Rule 25-22.082 Amended	Amendment to rules requiring competitive procurements for approval of utility self-build proposals, including procedures regarding bid-refreshing and information requirements regarding the self-build offer and evaluation process.
GA	2004	Amendment to Georgia Code 515-3-4-.04 Identification of Capacity Resources	Georgia General Assembly revision to the IRP Act, to include competitive procurement rules, including requirements for independent monitors
LA	2004	Market Based Mechanism Order (General Order, Docket No. R-26172 Sub Docket A)	Requirement that utilities use an RFP process to acquire and justify new resource acquisitions, including requirements for independent monitors and providing information to the public in advance of procurements
OK	2007	Title OCC, Subchapter 35: Electric Utilities – Amendments, Competitive Procurements	Specific requirements for competitive procurements necessary for filling new resource needs, including use of independent monitors and requirements related to affiliate bids and evaluation processes
OR	2006	PUC Order No. 06-446	Update of prior order providing guidelines for competitive procurements, including 13 guidelines for RFP design, bid evaluation and selection, role of an independent evaluator, treatment of self-build and affiliate offers, and other elements
UT	2005	Utah Energy Resource Procurement Act Statute (Title 54, Chapter 17)	Requirements for procurement process for new energy resources, including requirements for an independent monitor
	2007	Rules R746-420, R746-430, R746-440	Rules refining requirements for competitive procurements mandated in Title 54, Chapter 17 (2005)
WA	2003	General Order No. R-509	Requirements that utilities solicit supply offers, including: specifications for RFP contents, bid ranking, and contracts; bidder option to request an independent monitor to assist commission review if the utility or its affiliates participate as bidders.

[1] A formal rulemaking process has not been undertaken. Some investor-owned utilities are subject to specific procurement requirements arising from restructuring settlement agreement.

These approaches may limit opportunities for improper self-dealing by (a) establishing clear standards for procurement design and implementation to which utilities will be held accountable, and (b) making procurement development and evaluation transparent to regulators and market participants (as appropriate for each), so that improper conduct is easily observed.

Second, the process must be designed to encourage a competitive response from the market. Doing so will increase the likelihood that all suppliers with potentially valuable resources will participate in the procurement process, and will submit their most competitive offers. Ensuring a fair and objective process will encourage supplier participation by giving potential market participants confidence that their offers will be considered fairly against all other offers including any submitted by the utility or its affiliates. In order to submit offers that best reflect the utility's needs and system conditions, potential bidders need access to accurate and sufficiently comprehensive information on product specifications, model contract terms, credit and collateral requirements, relevant transmission constraints, costs to integrate generators into the transmission system, evaluation criteria, and other relevant factors. In addition, suppliers need to have a means of requesting supplemental information or clarifying information in ways open to all other competitors. However, while aiming for transparency of and access to information, utilities must also balance the need for confidentiality of certain supplier and utility information.

Finally, procurements must be designed to be efficient and timely, consistent with both the utility's own needs as well as those of market participants. The need to keep processes efficient yet thorough and fair creates tradeoffs in procurement design. For example, utilities should balance the cost of information requirements on suppliers with the need to obtain sufficient information to ensure that bidders offer suitable proposals. Similarly, streamlining regulatory reviews can help avoid creating time-consuming delays that may increase risk premiums that market participants build into their offers. With that in mind, it is helpful for regulators to review various early elements of procurement design (such as RFP instruments, evaluation approaches, and model contracts) prior to the utility issuing a final RFP as a means of limiting the extent of regulatory reviews in later procurement stages (e.g., review of final selections or final contracts). Reducing such delays will help to support the eventual procurement of the best resources from consumers' standpoint.

Although there are differences in particular procurement designs, most incremental resource procurements involve the following basic components, in which the utility:

- Identifies needed resources (such as through a long-range resource planning process);
- Designs an RFP instrument to solicit offers to provide needed resources, including potential public participation through comments on the draft instrument (including its anticipated evaluation process, and model contract terms and conditions);
- Receives bids in response to a final RFP from interested suppliers;

- Evaluates all offers and selects a winning offer, in either a single phase or multiple stage process (e.g., pre-qualification of bidders before issuing the RFP; or a review process to develop a short-list of the best set of offers);
- Informs bidders and regulators of resource selections;
- Enters into contract negotiations with the final award group; and
- Submits the results of the process (e.g., the award group with winning contracts) to the Commission for approval.

Box 1 illustrates these stages and other aspects of a specific procurement through a summary description of the competitive procurement process in Georgia.

Box 1

Incremental Supply Procurement Process in Georgia

In 2004, the Georgia General Assembly passed new rules requiring utilities to obtain incremental supply-side resources through an RFP process that includes use of an Independent Evaluator, application of utility codes of conduct, and various specific requirements for RFP content and public participation.[a] Georgia Power has procured a wide range of resources under these new rules, including: baseload and intermediate resources for a particular location (i.e., Northeast Georgia); baseload resources of varying potential terms (e.g., for 7-, 15- and 30-year periods); and long-term supply-side resources starting in 2016 (for which Georgia Power is offering a self-build nuclear facility). Georgia Power and its affiliates have been allowed to participate in these procurements.

In Georgia, RFP documents go through a public comment period that includes: issuance of a draft RFP; the utility's response to public comments on the draft RFP; public access to all drafts and comments through a public web site; and hosting of bidder conferences. Georgia's rules provide detailed requirements for substantive content of the RFP, including information on all evaluation criteria, transmission impacts, and procurement schedules. Bidders submit offers that include necessary details, such as price terms, technical details of resources relied upon, delivery locations, credit information, and market qualifications. The utilities undertake an evaluation process based on a "total cost impact analysis" as performed in a prior solicitation.

The Georgia Public Service Commission approves the IRP, the final RFP document, and the final resource selection through its "certification of need." After certification, the Commission allows the utility to recover an "additional amount" through rates which is "provided as an incentive for electric utilities to enter into purchase power agreements … [because] … if the Companies would only earn on their investments, not on their PPA expenses, they would be more inclined to build than buy." [b]

An Independent Evaluator oversees many phases and components of the procurement process, including review of all participant communications, review of RFP comments and utility responses to such comments, oversight of public web site, and development of an independent evaluation of offers. Additionally the Independent Evaluator provides interim and final reports on the procurement's performance. According to the Independent Evaluator, success in development of model agreements acceptable to all participants, as required by rules, has been "elusive."[c]

[a] Amendments to Georgia Code 515-3-4-.04, Identification of Capacity Resources.
[b] GA PSC Order, 15392-U, December 2002.
[C] Accion Group, Report to the Georgia Public Service Commission on the Georgia Power Company 2009 RFP, p.31.

2. *Resource Plans and Related Issues Preceding Procurements*

For utilities using competitive procurements for incremental resources, the process by which a utility determines what resource(s) to procure through a competitive solicitation often involves and is linked to preparation and regulatory review of a resource plan.

Irrespective of policies with respect to competitive procurements, most utilities with load-serving obligations in states with a traditional industry structure undertake some form of resource planning process. Broadly defined, such a process identifies incremental resource needs using a variety of lenses, including changes in customer requirements, resource adequacy, economics, portfolio mix or diversity, and external considerations (such as environmental policy requirements). In some states, this planning process may require oversight and approval by the state commission in formal integrated resource plan ("IRP") proceedings.[21] By identifying the utility's medium- to long-term resource deficiencies or opportunities, these planning processes are typically the first step in a procurement process in traditionally structured states relying on competitive procurements of incremental resources.

Resource plans have many implications for how resource needs are determined, managed and fulfilled that we do not address in this report. For the purposes of our examination of competitive procurements of incremental supply, we focus on the implications of utility plans for identifying the specific electricity product(s) to be procured from the market. For example, some utility procurements define products very broadly or flexibly, while others define products more narrowly.

More open and flexible procurements, for example, may simply request offers from any resource type/technology delivered to any points within the utility's service territory for a period of some unspecified duration. If a wide variety of types of resources may respond to such requests, the utility will need to compare price and non-price features among offers that may differ along many dimensions.[22] Comparison of such varied offers poses evaluation challenges that inevitably introduce subjectivity into the evaluation process. However, defining products in this way provides the market with the greatest flexibility to propose creative alternatives to meet the utilities' needs most cost-effectively.

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[21] For example, California, Colorado, Georgia, and Oklahoma require integrated resource plans (or similar plans requiring commission approval).

[22] Montana's utility, Northwest Energy issued an open RFP for baseload, dispatchable, shaped and wind resources. The RFP indicated that "The exact quantity and type of resources the Utility procures will substantially depend upon the economic and operational parameters of the bids received and therefore may not match the quantity and type of resources identified as beneficial in the Resource Procurement Plan." Northwest Energy, Request for Proposals, July 2, 2004, prepared by Lands Energy Consulting. Similarly, PacifiCorp's 2009 RFP, which requested 525 MW of supply that could be "prescheduled,", involved solicitation of offers providing for a minimum of 100 MW using any one of eight contractual approaches for terms of 10 to 35 years. PacifiCorp 2009 Request for Proposals, September 2005, Flexible Resource.

Competitive procurements can also define products and potential agreements more narrowly. They might, for example, request specific quantities of renewable power, demand response, or energy efficiency,[23] or request new baseload power plant supply located in or deliverable to a particular zone by a certain start date.[24] Commissions may influence the specificity of these narrower resources procurements through a resource planning process that attempts to identify the type of resources "best" suited to meet the utility's incremental needs. More narrowly defined procurements also eliminate some but not all of the evaluation challenges posed by broader procurements.

Despite the potential benefits of using an IRP process to arrive at a set of narrowly defined resource needs, such a process may result in product specifications based on planning assessments of hypothetical resources rather than on actual prices and resource alternatives offered by the market. For a variety of reasons, important differences may exist between the assumptions used in the planning process and the realities of the markets. Further, utilities may seek to change product definitions (or evaluation criteria) if changes in market conditions make initial resource selections made during planning stages imprudent. Under such circumstances, regulators often must determine whether and, if so, when to review the prudence of the utility's proposed changes. These reviews are likely to be difficult because such amendments may be proposed to avoid investments that are not in consumers' interests or to change opportunistically the terms of the procurement to promote the utility's preferred resources.

In some states, certain types of resources are exempt from commission or legislative requirements that otherwise call for competitive procurements of incremental supply. Exemptions are generally allowed for procurements involving small quantities (e.g., less than 100 megawatts ("MW")) or short durations (e.g., less than one year).[25] These exemptions are provided to avoid imposing excessive administrative burdens on the small, short-term supply purchases that utilities commonly make. While such exemptions provide the utility with needed flexibility to effectively manage a short-term portfolio to maintain resource balances, regulators should also be attentive to situations in which utilities use such exemptions to avoid competitive procurements for longer-term

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[23] In California, the Energy Action Plan creates specific targets for certain preferred resources (including renewable power, demand response, and energy efficiency) to be achieved through separate resource procurements. State of California Energy Commission and Public Utilities Commission, Energy Action Plan II, Implementation Roadmap for Energy Policies, September 21, 2005.

[24] For example, Georgia Power's 2011 RFP requests resources with interconnection to the Northeastern portion of Georgia's grid. Georgia Power, "Overview of the Georgia Power and Savannah Electric 2010 and 2011 RFPs." Southern California Edison's 2005 procurement sought only supply from new generation resources because of the perceived need to encourage new generation to mitigate potential market power and forecasted resource adequacy concerns in that area. Southern California Edison, 2006 Request for Offers, New Gen RFO, Transmittal Letter, V6.0 revised November 30, 2007.

[25] For example, procurements in Utah are required for resource additions greater than 100 MW and for longer than ten years. Energy Resource Procurement Act, 54-17-102. In Oregon, the criteria are 100 MW and five years. Public Utility Commission of Oregon, Order No. 06-446, p. 3.

resources which might produce offers that would otherwise offer favorable terms for customers.

Box 2

Dealing with capital-intensive, new and untested technologies

Much of the recent experience with utilities' competitive procurements has been limited to solicitation of and/or proposals for procurements of power from natural gas-fired facilities. For a variety of reasons, regulators and utilities may seek to depart from this trend. Recent experiences with using procurements to elicit proposals for baseload resources have varied. Some utilities have sought exemptions from competitive procurements in order to develop coal-fired facilities,[a] while others have asked for proposals (including self-build offers) using coal or nuclear generation technologies.[b]

Development of large, baseload, capital-intensive generation facilities (especially ones using advanced technologies) may raise new types of uncertainties in resource development. First, in some states, development, permitting, and construction risks for coal and nuclear facilities are typically greater than those for natural gas plants. Second, advanced power production technologies face greater technology uncertainty because of their less advanced stage of development. For projects involving advanced technologies (e.g., the next generation nuclear facility, or a large-scale coal facility with carbon capture and sequestration), it may be difficult – either prohibitively expensive or not commercially possible – for suppliers to obtain either equipment manufacturers' performance guarantees or EPC contractors' willingness to take on construction risk.

Capital-intensive advanced technologies pose unique challenges for competitive procurements. Are these risks and technology issues sufficient reason to allow utilities exemptions from competitive procurements? How should these risks, technology issues and need for unique supplier attributes be addressed within eligibility requirements and evaluation procedures? Are there means of effectively quantifying these risks? Are there innovative ways of sharing risks and developing technologies collaboratively that can be developed with potential suppliers, and then built into model contracts that assign an acceptable allocation of risks among suppliers, the utility and, ultimately, electricity customers? These questions are beyond the scope of this review, but are important considerations for policy makers interested in considering the next generation of advanced technologies and how best to use markets as a way to discipline costs associated with them. Further, because the large capital investments necessary for development of these types of resources pose potentially valuable opportunities for utilities to enter new resources into rate base, commissions should be aware that utilities may attempt to shield such projects from competition even in situations where market processes are applicable. Despite these challenges, the potential economic gains from imposing the market discipline of competitive procurements on development of capital-intensive and advanced technologies may be great. In particular, the scope for potential cost savings may be significantly greater than those under procurement of natural gas-fired resources. In light of the expected introduction of greenhouse gas emission controls in the future that will require development of advanced technologies, we encourage regulators and the industry to continue to examine these issues in other forums.

[a] Duke Power, Preliminary Application for Certificate of Public Convenience and Necessity, Cliffside Project, Submitted to the North Carolina Public Utility Commission, May 11, 2005; Public Utilities Commission of Colorado, Order of Settlement, Decision No. C05-0049, December 17, 2004.

[b] PacifiCorp considered benchmark coal resources in its 2009 Request for Proposals for Flexible Resources, and Georgia Power is considering nuclear resources in its 2016 Request for Proposals.

Procurement rules also often allow utilities to petition for exemption from rules requiring a competitive procurement. The reasons for such requests have varied, but have been related to reliability and development risk,[26] or utility financial condition.[27] Some state rules also explicitly allow utilities to petition for "emergency" exemptions if there is insufficient time to implement a full competitive procurement for needed resources.[28] However, some commissions have explicitly cautioned against abuse of such "emergency" self-build proposals, particularly those that arise after a competitive procurement that fails to identify needed resources.[29] For similar reasons, commissions may require that utilities submit a self-build offer to avoid the situation in which the utility rejects all offers in a competitive procurement, and then subsequently submits a self-build proposal to fill resource requirements. When considering such exemptions and requirements as allowed or required under their authorities, commissions must balance potential lost gains from a competitive procurement against the particular factors raised by the utility in its application.

3. *Procurement Oversight, Stakeholder Participation, and Utility Codes of Conduct*

Participation by suppliers, commissions, the public, and independent monitors can be important to ensuring a fair and objective process. Such participation early in the process can also help to avoid (or at least lessen) later regulatory disputes by providing opportunities for differences of opinion, misunderstandings, or information problems to be resolved ahead of the competitive solicitation itself.

a. *Independent Monitor*

Independent monitors have become an important component of procurement oversight in many of the incremental supply procurements, particularly when the procurement includes utility self-build proposals or affiliate bids. State policies, however, differ in their requirements relating to IMs. Apart from the threshold issue of determining

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[26] For example, although North Carolina has no formal requirements for competitive procurements, Duke Energy explicitly requested approval to forgo a competitive procurement given the nature of the proposed resources. Duke Power, Preliminary Application for Certificate of Public Convenience and Necessity, Cliffside Project, Submitted to the North Carolina Public Utility Commission, May 11, 2005.

[27] Public Service of Colorado requested, and was granted, exemption from procurement rules for a 500 MW coal-fired power plant. Among other reasons suggested, Public Service of Colorado argued the need for the project to maintain sufficient equity on financial balance sheet.

[28] For example, Public Utility Commission of Oregon, Order No. 06-446, p. 3. PacifiCorp argued that the purchase of a 500 MW power plant should be exempt from procurement requirements because it is a "time-limited resource opportunity of unique value to customers." *See*: Clearing Up, "PacifiCorp Signs Stealth Deal to Acquire 500-MW Generator," April 23, 2008; Public Utility Commission of Oregon, Order No. 06-446, August 10, 2006, p. 4. See also Ohio's newly enacted law (127 SB 221) that sets forth the market-condition criteria under which the Commission may not approve the winning bids (and market-based prices) of a competitive procurement process. Sec. 4928.142.(B)(3)

[29] For example, resources may not be selected if they fail to meet a competitive benchmark, such as short-term market purchases. Public Utility Commission of Oregon, Order No. 06-446, p. 5.

whether and when an IM is required to be part of the procurement process, the other key issues include:

- What are the IM's roles and responsibilities (e.g., oversee the utility's actions? Independently evaluate the bids? Select the winning offers?)
- Who selects the IM (e.g., the utility and/or the commission?)
- To whom does the IM report (e.g., the utility and/or the commission?)

Independent monitors are currently required in nearly all states that impose some procurement requirements, although there are exceptions.[30] In some states, IM monitors are required for all procurements;[31] in other states, IMs are required only if utility self-build or affiliate offers are considered.[32]

Using an IM involves many trade-offs in terms of costs and benefits to the process. The potential roles an IM may play (and services it may provide) include:

- Reviewing initial procurement documents (e.g., the RFP, model contracts, credit requirements);
- Overseeing communications with potential bidders, and between utility teams to comply with "codes of conduct";
- Reviewing utility bid evaluation methodologies, and in some cases even carrying out parallel independent bid evaluations;
- Monitoring contract negotiations; and
- Reporting to commission staff and supporting the regulatory review of the entire process and its results.

Appendix A provides a more detailed list of the various activities that IMs often perform.

By playing these roles, an IM may add substantial benefits, particularly in terms of maintaining process fairness and objectivity to mitigate the potential exercise of

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[30] Florida's Rule 25-22.082 does not require that competitive procurements use an independent monitor, although some procurements by Florida utilities may incorporate utility-hired monitors to evaluate certain procurement elements. For example, see Direct Testimony of Alan S. Taylor, In re: Florida Power and Light Company's Petition to Determine Need for West County Energy Center Units 1 and 2 Electrical Power Plant, Docket No. 02162-06.

[31] For example, Oregon (Public Utility Commission of Oregon, Order No. 06-446, p. 6), Louisiana (Louisiana Public Service Commission, General Order, Docket No. R-26172 Sub Docket A).

[32] For example, California requires an IM in all procurements in which the utility or its affiliates has a proposal. California Public Utilities Commission, Decision 04-12-048, Opinion Adopting Pacific Gas and Electric Company, Southern California Edison Company and San Diego Gas & Electric Company's Long-Term Procurement Plans, April 1, 2004.

improper self-dealing. However, an IM can also improve the efficiency of the process and the quality of the results. For example, the IM can monitor communications to ensure an appropriate level and substance of communications. The IM can assist in ensuring appropriate resolution of technical challenges that inevitably arise in the course of a complex competitive procurement. Similarly, the IM can monitor and report on the utility's conduct and the procurement's competitiveness as a way to help the commission evaluate whether the results of the procurement should be approved as consistent with just and reasonable rates. In addition to these important oversight roles, an IM may also provide substantive feedback on procurement design and "lessons learned" that can improve effectiveness of future procurements.

Against these benefits of including an IM are the costs to the process – especially the cost of hiring the IM, which can be substantial. However, as many states have determined, the benefits of IMs seem to outweigh these costs in most instances, and are a necessary element of a credible process where the utility itself has a financial stake in the outcome of the competitive procurement itself. In many states, legislation or commission rulings provide specific guidance on these activities, while other states provide no explicit guidance or requirements.[33]

Achievement of these IM benefits requires a degree of separation between independent monitors and the utilities they are overseeing. Thus, decisions about who selects the IM, and to whom the IM reports may affect their independence and their ability to fulfill their duties in effective ways. In some states, IMs are selected by commission staff, potentially with input from various stakeholders, including the utility and potential bidders.[34] In other states, the utility selects the IM, although the commission or its staff usually retains some control over the selection process.[35] In nearly all states, the soliciting utility is responsible for compensating the IM and, in many states, can recover such costs from rate payers (as part of the costs of the procured resources) or through fees imposed on bidders.[36]

[33] For example, Arizona's guidelines provide limited specification of IM duties. Arizona Corporation Commission, Decision No. 70032. In contrast, Utah's rules identify very specific IM roles and responsibilities. Utah Administrative Code, R746-420.

[34] For example, Oregon (Public Utility Commission of Oregon, Order No. 06-446, p. 6), and Utah (Utah Administrative Code, R746-420, Requests for Approval of a Solicitation Process, at R746-420-1).

[35] In Arizona, the Staff endorses a short-list of IMs from which the utility can select. Arizona Corporation Commission, Decision No. 70032, p. 3-4. In Louisiana, the Commission can reject the utility's proposed IM. Louisiana Public Service Commission, General Order, Docket No. R-26172 Sub Docket A.

[36] In Utah, the utility charges "reasonable" bid fees of up to $10,000 per bid to defray IM costs, but can also recover any remaining costs through customer rates. Utah Administrative Code, R746-420, Requests for Approval of a Solicitation Process, at R746-420-5. Georgia also allows the utility to recover IM costs through bid fees up to $10,000 per bid. Georgia Code 515-3-4-.04.

b. *Public (or Stakeholder) Participation*

While public participation may occur at any stage of a procurement process, most activity tends to occur in certain discrete periods: (a) during the policy development period when a commission is considering whether to require competitive processes and what structures and rules to require; (b) prior to a particular procurement, when the utility is developing RFP instruments and procedures, defining products and contract terms, and determining information to provide to potential bidders; (c) immediately after the RFP is issued and potential market participants have a chance to gather any additional information they need to respond to the RFP; (d) during a formal process the commission uses to review the results of the procurement; and (e) after the procurement process when the commission is considering what "lessons learned" can lead to process improvements in future procurements.

While public participation during these phases may add time to their completion, such participation may avoid delays later in the process by minimizing incomplete supplier offers and by decreasing the opportunity for misunderstandings or disputes about bid requirements, other RFP terms and conditions, and evaluation procedures. Final RFPs often reflect input from market participants and other interveners obtained through comments on draft RFPs.[37] Workshops provide an opportunity for more informal discussions amongst the procuring utility, regulators, and potential bidders about draft or final RFPs. Such conferences may also provide a means for utilities to clarify particular aspects of RFP terms and conditions.

c. *Utility Codes of Conduct*

Because of the inherent and well-recognized potential conflicts of interest that arise in competitive procurement processes where the utility is both a buyer and potential supplier of power, utilities and their affiliates are typically required to act under "codes of conduct" that limit and/or guide certain types of communications and interactions between utility employees. In particular, these codes of conduct limit and guide communications between the utility's personnel with different functions: the team of individuals developing utility self-build proposals, the team evaluating competitive offers, the team providing estimates of transmission impacts, and the team administering the utility's transmission functions.[38] By operating pursuant to these conduct codes and

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[37] For example, comments to draft RFPs have be requested by utilities in various states, including Georgia, Louisiana, Oregon, and Utah. For example, s*ee*, the Georgia PSC maintains a web site providing access to draft RFPs and comments from all interveners. <https://www.gpscie.com/_gpscie/home.asp >. See also, Entergy Services Inc., 2006 Request for Proposals for Long-term Resources, April 17, 2006.

[38] For example, *see*, Georgia Public Utilities Commission Rules, 515-3-4-.04; Utah administrative Code R746-420, Requests for Approval of a Solicitation Process. We also note that FERC's Standards of Conduct govern interactions between utility personnel involved in certain transmission functions and other personnel. *See*, Standards of Conduct for Transmission Providers (see, e.g., 122 FERC ¶ 61,263, Standards of Conduct for Transmission Providers Docket No. RM07-1-000, Notice of Proposed Rulemaking, March 21, 2008)

standards, the utility's bid evaluation team is less likely to bias decisions in favor of the utility's or its affiliate's proposals, and the utility's teams developing self-build or affiliate offers are less likely to have advantageous access to confidential information not available to all bidders. IMs often oversee such interactions to ensure that utilities are not in violation of these prohibitions and requirements.

Procurement processes vary in the means by which any offers from an affiliate and self-build proposals are introduced into the solicitation process. In some cases, such offers must be submitted under seal ahead of those of other bidders to provide assurance that these offers have not been shaped with knowledge of information from other proposals.[39] In other cases, utilities compare supplier offers against utility or market benchmarks whose content may or may not be known to suppliers prior the submission of their offers. The utility may choose to reject all offers that fail to beat either type of benchmark. In all of these cases, there need to be safeguards so that market participants know in advance the rules for how affiliate proposals and self-build offers will be treated.

4. *Design/Structure of the Evaluation Process*

a. *Evaluation Timing*

The process of evaluating and selecting offers in incremental supply procurements takes at least many months. During this time period, bidders are typically required to honor the terms of their initial offers, which can create financial risk for suppliers due to fluctuations in the cost of construction materials, fuel prices and other cost factors. Because suppliers are likely to add risk premiums to their offers to capture such risks, procurements that minimize the time between submission of offers and awarding of contracts are likely to encourage offers with lower prices, all else equal. By reducing these supplier risks, keeping the evaluation period as short as possible helps to reduce such risks and costs. However, it is difficult to eliminate such costs altogether. The evaluation of incremental resource offers is, by its nature, highly complex and time consuming due to the need for multiple stages of analysis, development of supplemental data, complex production simulation modeling, and multi-attribute comparisons of offers. Thus, an evaluation that is hurried may result in poor resource choices.

While some procurements result in the selection of bidders within three to four months,[40] it is not unusual for procurements to take significantly longer. In practice,

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[39] An IM can manage the receipt of supplier bids and dissemination of certain parts of the bids to the evaluation team during different stages of the process as ways to prevent any (intentional or unintentional) preferential treatment.

[40] For example, in Montana, Northwest Energy's 2004 all-source procurement scheduled roughly four months between bid submission and contract signing. Northwest Energy, Request for Proposals, Issued July 2, 2004. Similarly, PacifiCorp's 2009 RFP was scheduled to achieve a selected offer for more detailed

evaluation periods will reflect many factors such as the number of offers anticipated, the complexity of the required quantitative evaluations given system conditions, the number and complexity of evaluation criteria, and the diversity of supply offers in terms of contractual forms, resource types, and other factors that complicate offer evaluation. Given such differences, utilities should tailor procurement schedules to the types of resources that are being procured.[41]

Given the costs of delays in competitive procurements, procurement design should consider taking steps to shorten evaluation periods and taking steps to mitigate against unanticipated events that may create delays. For example, public participation prior to issuance of the RFP may reduce delays by increasing the likelihood that suppliers conform with bid requirements. Similarly, IMs may have to help mediate unanticipated events that lead to disputes or require arbitration of appropriate procedures.

b. *Contract Negotiation, Including Model Agreements and Bid Refreshing*

Just as with the process to purchase a house, the multi-faceted nature of incremental resource procurements suggests that some degree of negotiation after initial bids are received is inevitable. The extent of such negotiations can vary from relatively minor adjustments in the RFP's model contract terms, to negotiations over payment terms and more substantive elements on contract terms. Allowing broad negotiations after offer selection creates incentives for suppliers to understate initial offers and then attempt to recapture value during contract negotiations. Such broad negotiations may also reduce the transparency of the procurement process. However, some scope for negotiation in the terms of incremental resource agreements is important to ensure that potential modifications that expand the scope of benefits to suppliers and utilities can be considered.

Competitive procurements often make their policies regarding negotiation of contract terms explicit to ensure that both the utility and the supplier have common expectations about the likelihood of such negotiations when initial offers are being reviewed. In particular, utilities have explicitly allowed an opportunity for suppliers to "refresh" offers (usually only downwards) at a pre-determined point in the evaluation process, often after a short-list of offers has been identified.[42] Allowing suppliers to "refresh" offers

negotiations within three months. PacifiCorp 2009 Request for Proposals, September 2005, Flexible Resource, December 1, 2005.

[41] For example, Southern California Edison's 2006 procurement for new generation includes both a Fast Track (five months) for projects that are well into or have completed development phases and are ready to move to construction phases and a Standard Track (14 months) for projects that are earlier in the development process. Southern California Edison, 2006 Request for Offers, New Gen RFO, Transmittal Letter, August 14, 2006.

[42] For example, see Benson, Elizabeth, "Report of Elizabeth Benson, Process Independent Monitor of the Entergy Services Inc. 2006 Request for Proposals for Long-term Supply-side Resources," Docket No. U-30192. September 14, 2007.

may reduce their financial risks given the potentially long delays between bid submission and the awarding of contracts. Of course, such an opportunity also invites suppliers to understate their initial offers. Also, to the extent that there are opportunities for the utility to refresh the cost terms of its self-build proposals, other competitive suppliers should also be given similar opportunities. In some cases, indicative offers are used as a means to move offers into a final stage at which the suppliers sharpen their pencils and refresh their bids.[43]

Most RFPs include model contracts, which provide bidders with guidance about the utility's preferred terms and conditions and about expected allocations of risk among the buyer and seller which would affect the price terms offered by the bidder. The value of such model contracts is that they provide suppliers with a common set of assumptions about the overall shape of an ultimate transaction. The more these terms parallel those which the utility itself will face if it proposes a self-build offer, the fairer will be the competition between proposals from third parties and the utility and the less likely there will be proposal differences that lead to improper self-dealing.

However, model contracts accompanied by tight limitations on contract negotiations may unnecessarily constrain the range of mutually beneficial agreements between suppliers and utilities. Many utilities recognize the potential cost of such constraints and allow suppliers to propose alternative contractual arrangements as part of their initial offer. In contrast, amendments to model contracts may penalize the supplier's offer, since the bidder is typically prohibited from raising a final offer price relative to the indicative offer. In either case, procurements should clearly state the conditions related to amendments to model contracts to avoid a situation in which some suppliers design their offers around model agreements to avoid penalties, while other suppliers offer amendments to model agreements under the belief they will be able to negotiate a more favorable allocation of risk without being penalized in their price terms.

5. *Commission Reviews of Procurement Process and Results*

State commissions have many opportunities to review and approve particular aspects of the procurement process. Regulators often do so – formally or informally – during certain periods: (1) an IRP process when the utility may be identifying the type and amount of incremental resources it plans to procure and/or build; (2) RFP design, which may occur if the utility proposes a design in advance of implementing the RFP; (3) offer evaluation and selection; or (4) the approval of agreements (or proposed self-build investments) and cost-recovery related to them.

When making such choices, commissions face not unfamiliar problems of balancing their role of providing prescriptive policy guidance and holding the utility management

[43] Where this occurs, it is one more instance in which the utility's team responsible for refreshing its self-build offer should not have access to commercially sensitive information from other potential suppliers' bids.

responsible and accountable for its own decisions. While commissions in some states actively participate in overseeing different stages of procurements, other commissions take a relatively light-handed role in intervening in utility management analysis and decision-making until utility proposals are formally submitted for approval.[44]

A critical issue affecting those states that have chosen to use a competitive procurement process for incremental resources, of course, is the signals sent by regulatory reviews and decisions with regard to the regulators' actual commitment to the competitive process and the assurances regulators will provide with regard to recovery of the costs of transactions emanating from the competitive process. Regulators thus end up balancing competing objectives. On the one hand, they must consider the need to provide assurance to the market about cost-recovery. On the other hand, they need to maintain their ability to act on consumers' behalf to deter imprudent utility actions and maintain "fair and just" energy prices.

Commission rulings that allow the market (and investors) to infer relatively greater commitment to the outcomes of a competitive procurement process may reduce uncertainty about the utility's ability to recover the costs of PPA(s) that result from a procurement. This in turn can reduce the associated regulatory and financial risks, and any cost premiums associated with them.[45] For complex competitive procurements for incremental supplies, it may be difficult (if not impossible) for regulators to provide utilities with a before-the-fact, iron-clad commitment to allow cost recovery for any transactions that result from a competitive procurement found to have been fully competitive (unless such regulatory authority were sanctioned in a state's legislation). That said, once regulators (or their legislators) have called for reliance on competitive procurements, the actions of regulators to show their willingness to allow cost-recovery of transactions resulting from solicitations found to be competitive will help to buttress a favorable investment climate in the state. Commission approvals may also provide other market participants with greater confidence that the commission supports the outcome of the procurement process. Thus, for example, approval of the utility's proposed RFP process may provide the market with greater confidence that the commission supports the procurement process and that the procurement will eventually result in signed agreements with suppliers.

[44] Members of the North Carolina PUC have referred to their role as a quasi-judicial entity, which responds to utility/regulatory issues and controversies brought to the commission to resolve. At the other end of the spectrum on procurement issues is the Maine PUC, which is the entity that actually decides what resource(s) to select in the context of procurements and then assigns such resources and related costs to regulated utilities in the state. (Ohio's new law gives the PUC authority to select winning offers of competitive procurements under some circumstances.) In the middle are a large number of states with traditional or hybrid electric industry structures (e.g., Arizona, California, Georgia, Louisiana, Oklahoma) with an array of utility practices, in which the state gives more or less guidance over preferred procurement approaches, and different levels of supervision and decision-making about utility actions in different phases of the RFP process.

[45] All else equal, the longer that a bidder has to keep its resource out of the market while its bid is being considered by a utility in the course of a procurement, the higher the opportunity costs and other risk premium will be built into the offer price.

D. IMPLEMENTING THE PROCUREMENT: THE UTILITY'S EVALUATION OF OFFERS

1. *Overview*

As described earlier, offers to provide incremental resources typically vary along multiple dimensions related to the type and character of resources offered, and the structure of the proposed contractual arrangements. Because incremental supply offers may differ along many of these dimensions, utility evaluations must consider trade-offs across various criteria related to economic, reliability and other considerations. Key criteria for evaluation of offers include:

- Price, on a dollar per kilowatt and a dollar per megawatt-hour basis, reflecting anticipated fixed and variable payments given likely dispatch as part of the utility's system;
- System benefits (related to congestion relief or transmission losses) or costs (in terms of transmission upgrades necessary to enable a resource to power in accordance with the proposed agreement);
- Shifts in risks among the utility, the seller and retail customers associated with various provisions in the contract, such as fuel price indices, availability penalties, collateral requirements of the utility and supplier; and
- Other non-price policy factors and considerations (e.g., environmental impacts, development risk for a new project, the utility's fuel or portfolio diversity, etc.).

A successful evaluation should attempt to account for these costs and risks, assign weights that appropriately reflect the value proposition (and risks) to customers, make comparable evaluations across all offers (including self-build and affiliate offers), and complete evaluations in a timely and efficient fashion to provide proper incentives for bidders.

To reduce evaluation costs and the time between offer submission and selection, evaluations typically proceed in three stages, including: (i) identification of bidders and/or offers meeting basic eligibility requirements; (ii) a preliminary evaluation to identify a "short list" composed of the "best" offers; and (iii) a full evaluation of "short-list" offers to identify a final selection. While most incremental resource procurements follow such a three-step process, there is little uniformity in how (and whether) particular evaluation criteria are considered in each of these stages. However, in general, initial eligibility criteria are utilized primarily to ensure that offers meet financial and electricity market participation criteria necessary to deliver power reliably.

2. *Economic Modeling of the Benefits and Costs of the Offer as Part of the Utility's System*

Evaluation of offers – at least the set of short-listed offers – typically involves an analysis of how an offer and/or groups of offers, interacts with the utility's system. This typically involves a series of simulations of the system with different base-case conditions and with different offers or groups of offers, along with sensitivity analysis exploring the robustness of outcomes under different fuel prices conditions.

Final evaluation of the costs of proposed power supplies, including associated transmission-related impacts,[46] typically relies on the use of highly detailed production cost models among other things. These models have a long history of use within the context of utility planning and regulatory proceedings. As such, we do not revisit the many issues arising in the proper valuation of the costs of alternative electricity supply resources. Several issues regarding the use of these models within the competitive procurement context are, however, worth noting.

Due to their complexity, production cost models (and their data inputs and assumptions) used to evaluate and compare the economic costs of various offers may have limited transparency to market participants. While frustrating to market participants concerned about whether their proposals have been treated fairly and objectively, there are inherent challenges in opening these processes up for public scrutiny. Competitive procurements may take several approaches to ensuring that modeling is performed in ways that support fair and objective evaluations. First, utilities might rely on the same production cost models used in other regulatory proceedings. Past experience with such models may reduce the cost of oversight of the evaluation process. Second, regulators or independent monitors may review portions of the utility's evaluation studies, perform completely independent evaluations of all offers, or perform evaluations using the same models as the utility's evaluation team. In particular, review of modeling assumptions and data prior to the submission of bids may allow any controversial issues to be identified and resolved prior to the evaluation stage.[47]

To the extent possible, utilities should aim to provide bidders with information about input assumptions used in these models, such as demand forecasts and key parameters of other system resources. This will allow suppliers to shape their competitive offers to be more attractive than other offers. However, utilities may find it prudent under some circumstances to revise these assumptions during the course of the evaluation process, so that evaluations reflect up-to-date market conditions. Procedures for updating data

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[46] In Section VI.D.7, "Transmission", we discuss these types of costs, including congestion impacts, losses, and any transmission-system upgrades that may be needed to integrate a new resource into the utility's transmission system.

[47] As these evaluations frequently rely on assumptions and models developed as a part of the utility's IRP process, the evaluation structure has already undergone some degree of review. For an example of an independent model evaluation, *see,* Potomac Economics, Independent Monitoring of the Evaluation of Proposals for Entergy Long-Term Supply-Side Resources, Solid-Fuel Final Report, September 2007.

should be specified prior to evaluation and be sensitive to concerns about the transparency of evaluation procedures or improper self-dealing.[48] Certain design procedures might mitigate these tensions, such as indexing key assumptions to publicly available metrics. The involvement of IMs may mitigate such concerns through review of modeling assumptions or implementation of parallel, independent evaluations.

In some procurements, offers are compared to "benchmarks" that reflect estimates (but not actual offers) for a utility self-build facility or purchase of power on short-term wholesale markets. The potential use of such benchmarks may present a dilemma for regulators, however, if they are faced with having to decide what to do in the event that no offers beat the assumed benchmarks, that the benchmarks do not reflect the actual products being procured in the RFP, or that cost-recovery policies for utility self-build proposals do not bind the utility to these benchmarks.

Finally, choice of evaluation methodology may have implications for comparing offers that differ along certain dimensions. For example, comparison of offers of different duration (e.g., comparing a 15-year contract offer to a "life-of-unit" self-build proposal) is sensitive to methodology choice, since these methodologies implicitly make different assumptions about the prices that prevail for periods when offers of different duration do not overlap.[49] End-effects associated with offers of different duration can have a large impact on overall system benefits and costs, and therefore must be treated with care when evaluating proposals with significantly different terms. Commission guidance on these and similar technical issues prior to issuing an RFP may contribute to more efficient processes in the end.

3. *Economic and Financial Risks*

Competitive procurement of incremental resources involves important questions associated with who bears the burden of the financial and economic risks in power supply arrangements, as between:

- the power supplier (as seller) and the utility (as buyer) in a PPA;
- the utility and its customers in a PPA; or
- the utility and its customers in a self-build proposal in which commissions will eventually determine cost-recovery on the investment.

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[48] For example, *see*, Staff of the Public Utilities Commission of the State of Colorado, Report on Public Service Company of Colorado's 2003 Least-Cost Resource Plan, Volume 1: Commission Rules and Practices, Docket No. 07M-147E, June 14, 2007.

[49] Boston Pacific Company. "Bid Evaluation Methods in Competitive Solicitations: A White Paper on Techniques Used to Evaluate Power Supply Proposals with Unequal Lives," prepared for Calpine Corporation.

In fact, because of their ability to influence the allocation of certain risks, competitive procurements have begun to be used in utility settings as a means to address core issues associated with such risks.

The cost of arranging for and obtaining generation services on behalf of retail customers depends on many uncertainties. Regulators are quite familiar with many of these risks: the risk of fuel price increases; the risk that it will cost more to construct a plant than originally expected; the risk that new laws will be enacted that change the future investment requirements and operating costs at a power plant; the risk that a plant will not perform as expected over time; and so forth. Regulators understand these and other categories of risk and have addressed them in a variety of ways over time.

The magnitude of such risks depends on many factors. In particular, three risk factors are important to competitive procurement of incremental supply: (i) the assignment of obligations and responsibilities between the buyer and the seller, as set forth in agreements; (ii) the character of inherent risks associated with the type of resource involved in offers; and (iii) the risks associated with the development status of power plant projects underlying different supply offers.

Table 7:
Illustrative Shifts in Financial Risks for Alternative Supplier Agreement Structures
∗ = Risk shifted to supplier relative to a self-build with no comparable agreements in place (illustrative)

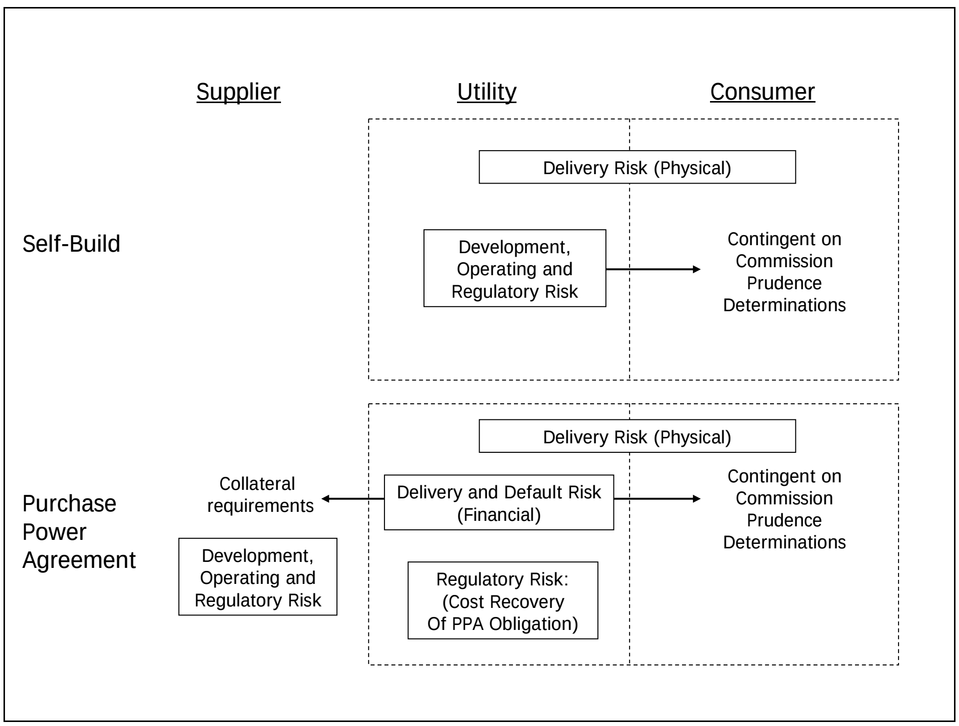
Types of Risks (examples):	Engineering, Procurement, Construction Agreement	Asset Purchase and Sale Agreement	Tolling Agreement	Purchase Power Agreement
Development Risks:				
Construction Risk (timing, cost)	∗	∗	∗	∗
Operating Performance and Cost Risk				
Fuel Price				∗
Heat Rate Performance O & M Costs Specific to a Plant Power Plant Availability			∗	∗
Regulatory Risk				
Cost-recovery Risk			∗	∗
Environmental Policy Risk			∗	∗

Note: Some risks can be shared between suppliers and the utility (and its customers) through various means, such as indexing measures relying on fuel price or construction cost indexes. Indexing can control for market risks, but not idiosyncratic risks associated with supplier performance.

How these risks are allocated between third-party suppliers, the utility (as buyer in a PPA or as a power plant owner) and retail customers is a fundamental issue for utilities and regulators relying upon competitive procurements. Table 7 shows how the terms of PPAs can shift various project risks away from the utility (and its retail customers) to suppliers, as compared to utility self-build. With a self-build, these risks are distributed between utilities and customers depending on commission rulings.[50] By contrast, at the other end of the spectrum are PPAs. These agreements shift many of these risks to suppliers, by requiring, for example, that they deliver replacement power at a certain price even if fuel prices increase or pay other penalties if the plant performs poorly. Other types of agreements, such as those presented in Table 7, shift certain pieces of these financial risks.

The development, operating and regulatory risks identified in Table 7 reflect only a portion of the entire risk story. Figure 1 provides a stylized illustration of the distribution of risks under a PPA, on the one hand, and a self-build approach, on the other. There are various ways to assign responsibility for certain risks identified in Figure 1. For example, default and delivery risks from PPAs can be mitigated through supplier collateral requirements and/or other performance penalties. Also, utility risks from uncertainty over recovery of the costs of contractual agreements made with suppliers (so-called "debt equivalency") can be mitigated through certain measures. The sections that follow provide further discussion of each of these risks.

Figure 1
Illustrative Distribution of Financial Risks of
Self-Build and Purchase Power Agreement Offers for Retail Supply



[50] Such regulatory decisions include, for example, determinations as to the prudence of utility actions when the it proposes to add investment to rate base (whether at the point when the project becomes used and useful, or over time as new capital investments are required at the facility). Other cost recovery decisions are made over the life of the plant (e.g., utility fuel purchases of fuel and plant operating performance.)

Other aspects of agreement structure can also impact the distribution of financial risks. For example, financial risks to suppliers can be shifted back to the utility (and its customers) by making energy-related payment terms dependent on market prices as reflected in publicly available price indices, or by making capacity-related payment terms tied to changes in construction cost indices during the construction period. By using these and other mechanisms, utilities and commissions can design procurements to achieve a desired distribution of these risks and – to some degree – avoid the challenges of reliably assessing the economic cost imposed by these risks.

In principle, evaluations should aim to account for the allocation of various risks when comparing alternative supply offers. Figure 1 illustrates how the distribution of these financial risks can vary dramatically between a PPA and a utility self-build project. While PPAs shift much of the development and operational risks traditionally associated with a cost-of-service regulatory model to third-party suppliers, they leave utilities with the risk that regulators may decide not to approve cost recovery for contracted power. Because of this risk, many utilities condition any contracts they sign with bidders (as a result of a procurement) upon regulatory approvals of cost-recovery of contract payments.

Measuring the implications of alternative contractual forms for the transfer of risk is complicated by many factors. First, many of the uncertainties are difficult to quantity given limited information and limited experience with the relevant risk. The shifting of risk is never as tidy as suggested in Figure 1 despite contractual provisions.[51]

Second, the relevant financial risks vary not only with contractual form but also with other attributes of suppliers' offers, such as the type of proposed technology. Some technologies (e.g., gas-fired combustion turbines) rely on equipment for which there is significant construction and operating experience; this creates relatively low financial risk. By contrast, other technologies require plant construction tailored to particular site conditions (e.g., large baseload facilities) or have relatively little operating experience (e.g., coal-fired integrated gasification combined cycle facilities). Further, uncertainty in future fuel prices, future environmental policy (particularly with regard to greenhouse gas emissions), and transmission infrastructure availability (e.g., for remote wind power) may create differences in financial risks of competing offers that are difficult to compare.

Finally, a contract framework may not fully capture certain development risks faced by the utility due to its obligation to maintain the reliability of the electric system. Thus, while some contractual provisions, such as collateral requirements, may mitigate certain financial aspects of development and delivery risks, they may not mitigate the physical risk that suppliers fail to develop generation resources needed to maintain system adequacy requirements.

[51] For example, EPC agreements may not fully shift development risks given contractual clauses that provide contractors with opportunities to plea for changes in original agreement terms, including change orders that inevitably occur given the difficulty of fully specifying the facility prior to construction.

4. *Credit*

Utilities that enter into PPAs face the risk that suppliers will be unable or unwilling to deliver in accordance with the agreement's terms. In parallel, suppliers face the risk that the utility will be unable to pay for contracted-for supplies. These uncertainties create financial risks because utilities may incur higher costs to replace supplies that are not delivered, or because the seller may lose revenues if a utility bankruptcy or regulatory action undermines the utility's ability to pay what is owed to the seller. To mitigate these and other financial risks, utility procurement processes introduce various means to evaluate the credit of sellers and to identify suppliers less likely to impose such risks. In addition, the PPAs can create incentives for suppliers and utilities to fulfill agreements as specified, and can minimize either party's financial losses in the event the other fails to perform.

One typical requirement in competitive procurements is a minimum credit rating that all bidders are required to meet. When used, such criteria should be transparent to suppliers so they have sufficient opportunity to address any credit deficiencies and to avoid such standards from inadvertently excluding suppliers from participating in the procurement.

Potentially more important than these credit standards are the financial guarantees or collateral requirements imposed on suppliers (and in some cases, of the utility as the buyer). These guarantees ensure that the counterparties to the PPA have access to sufficient funds to recover contractual penalties or remedies in the event that either the supplier or the utility cannot fulfill its obligations under the agreement. By ensuring the availability of these funds, the incentive to renege on the agreement's terms is reduced, and funds are available to compensate for the corresponding financial losses, such as utility losses arising from the need to replace power the supplier has failed to deliver.

The following list identifies key issues related to the design of supplier collateral requirements and are discussed in further detail in Appendix B (along with a summary of collateral requirements in selective procurements):

- *The level of financial guarantees.* The level of credit required should reflect a balance between (a) the benefits of insuring against financial losses and creating proper supplier incentives, and (b) the costs of imposing additional financial requirements on suppliers that are likely to increase the price of their offers (or the depth of offers submitted into the procurement). Some methodologies, such as those reflecting mark-to-market accounting, adjust the required level of financial guarantees to market conditions over time.[52] Utilities that make explicit the assumptions and methodology used in setting required levels of credit

[52] KEMA, "The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement," prepared for the California Energy Commission, CEC-300-2006-014, 2006, p. 6.

provide regulators and stakeholders with greater opportunity to assure the reasonableness of these requirements.[53]

- *Collateral requirements during procurement*. To ensure that suppliers' offers are sufficiently developed and financially credible, some utilities require bid deposits when offers are initially submitted, and/or require financial guarantees of the offers chosen for the "short-list" of considered offers. However, such requirements may act as a barrier to entry for smaller and less-well-financed suppliers, which may be a particular constraint in some procurements, such as those for renewable resources.[54] As a result of this trade-off, regulators and utilities should carefully consider the likelihood that non-bona-fide offers will be a problem, as regulators/utilities determine whether and what kind of bid deposits and other financial guarantees to require in the initial stages of offer submission and review.

- *Collateral requirements over the contract life-cycle.* The level of financial guarantee necessary to address delivery risk varies over the project's life-cycle, with different risks associated with bid selection, development and operation stages. PPAs should appropriately address these changing realities over the course of the supply agreement.

- *Flexibility in the means of fulfilling collateral requirements.* To minimize the cost to suppliers of providing collateral, utilities can provide suppliers with alternative means of fulfilling these requirements. In addition to letters of credit, financial guaranties from credit-worthy entities, and cash, the utility may consider other forms of guarantee, including second liens, claims to plant warranties or insurance policies, or step-in rights, in which the utility can take-over project development in the event of developer default.[55]

5. *Debt Equivalency* [56]

Over the years, utility obligations made under PPAs with third party suppliers have given rise to concerns about the best way to assess the implications of such financial risks on

[53] For example, in PacifiCorp's 2012 RFP process, delays in producing details regarding credit requirements and a justification for the credit approach eventually proposed raised concerns for the Independent Evaluator and various stakeholders. Merrimack Energy Group, Inc., "Report of the Independent Evaluator Regarding PacifiCorp's 2012 Request for Proposals for Base Load Resources" August 30, 2006.

[54] KEMA reports that short-list deposits for proxy projects in California Renewables RFPs were $300,000 in three of three of ten RFPs reviewed and over $1.5 million in another. KEMA, 2006, p.4 and 11-11.

[55] Aspen Environmental Group and Sentech, "Lowering the Effective Cost of Capital for Generation Projects, California Credit Policies Report, Summary of June 27, 2006 Workshop," prepared for the California Energy Commission, CEC-100-2007-001, 2007.

[56] Several references provide a broad overview of debt equivalency issues, including: Brattle Group, "Understanding Debt Imputation Issues," prepared for the Edison Electric Institute, 2008; GF Energy LLC, 2005.

utilities and their investors. In general, there are two issues associated with financial and ratemaking treatment of PPAs that are relevant in the context of competitive procurements.

First, under a PPA, the utility's contractual obligations to the supplier may create a financial risk if this obligation is not matched with a correspondingly firm expectation about the utility's ability to recover such costs from consumers in rates. This financial risk may arise because PPAs set up binding commitments that must be paid under the contract, such as certain fixed payments for available capacity or take-or-pay energy payments. The lack of a corresponding regulatory promise of cost recovery would thus create a potential financial risk for the utility. Second, despite these potential risks, commissions have traditionally treated utilitys' obligations to pay suppliers under PPAs as expenses for ratemaking purposes, thus allowing the utility no opportunity to earn a financial return; by contrast, when utilities pursue capital investments (such as self-build power plant proposals), the utility has the opportunity to earn a return of and on its investment. This can affect not only value of the utility's investment opportunities, but also its capital structure, in some circumstances. While not generally recognized as such by commissions, the utility's commitments under PPAs are generally recognized by credit-rating agencies as debt-like obligations on utility balance sheets. Because these credit ratings affect utilities' overall cost of borrowing on debt markets, a PPA might affect a utility's cost of capital irrespective of commission treatment of PPAs. As a result of these issues, utilities are concerned with commission treatment of a number of related issues, including commitment to PPA cost recovery, access to adequate investment opportunities, and the impact of PPA's on utility capital structure. As a result, so-called "debt equivalency" issues have become an area of tension as commissions expect regulated utilities to undertake procurement processes that may lead to PPAs.

Over time, two basic approaches to addressing debt equivalency issues have evolved. In one, these issues are addressed as part of the overall utility ratemaking process. In a utility's rate case during which its capital structure and cost of capital are determined, regulators consider what adjustments (if any) to a utility's allowed returns (e.g., cost of equity, capital structure) are appropriate in order to acknowledge impacts on the utility when it enters into PPAs with debt-like obligations. In the other approach, these issues are addressed during the evaluation of PPAs when the utility compares offers from third parties to those of a utility self-build proposal. In this approach, the utility makes adjustments to the economic cost of PPA offers to reflect the inferred value of the PPAs' impact on the utility's debt costs. (Appendix C provides further details on construction of such adders.)

In general, regulatory decisions about how best to adjust any inferred debt are complicated by the less-than-complete empirical evidence available on the financial risks associated with PPAs versus other means of supply. To date, there is relatively little research that has assessed how alternative means of fulfilling resource needs impact a utility's overall cost of debt or return on equity.[57] In fact, there is even uncertainty regarding how PPAs impact the credit ratings developed by credit-rating agencies. While certain credit agencies have clearly described certain quantitative balance sheet adjustments made for PPAs, they also note that these are only one among many possible adjustments that may affect a utility's credit rating.[58] However, because many of these other considerations are less clearly described and are more qualitative in nature, determining a PPA's net impact on utility credit ratings is difficult. These considerations again caution against assessment of debt equivalency, or any risk factor, outside of a comprehensive evaluation that accounts for all of the various risks posed by alternative utility obligations and commitments from the standpoint of consumers, while leaving the utility fairly compensated for its financial risks. These issues are normally addressed by commissions in general rate cases in which regulators examine the capital structure and cost of capital of the utilities they regulate.

State policies regarding debt equivalency vary substantially and continue to evolve. A few states have allowed adjustments for inferred debt associated with PPAs in rate proceedings.[59] For example, in Colorado, Public Service Company of Colorado's equity ratio was increased to account for the debt equivalent value of PPAs on the company's balance sheet.[60] More common is the use of debt equivalency "adders,"[61] although many commissions have disallowed the use of adders proposed by procuring utilities.[62] In states that allow the use of debt equivalency adders, the quantitative measure of financial risk used in these adders has varied significantly.[63]

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[57] One study suggests that PPAs have little effect on a utility's cost of capital, while utility self-builds actually raise the utility's cost of capital. While various limitations to this study caution against reaching any broad conclusions from its results, the results do suggest that it is important to understand the risk tradeoffs posed by alternative agreement forms when assessing the risk posed by any individual agreement. Kahn, Edward et al., "Impact of power purchased from non-utilities on the utility cost of capital," *Utilities Policy* 5(1): 3-11, 1995.

[58] For example, Standard & Poors notes: "That said, PPAs also benefit utilities that enter into contracts with supplier because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk." Standard & Poor's. "Standard & Poor's Methodology For Imputing Debt for U.S. Utilities' Power Purchase Agreements," Ratings Direct, May 7, 2007.

[59] For example, Colorado, Florida, and Wisconsin.

[60] *See* Colorado Public Utilities Commission, Final Decision, C05-0049, ¶95, December 17, 2004.

[61] For example, procurements in Florida, Louisiana, and Washington allow debt equivalency adjustments.

[62] For example, procurements in California, Colorado, Connecticut, and Georgia do not use debt equivalency adjustments. In some cases, this decision was reached as a result of settlement, rather than commission policy. For example, *see* Public Utilities Commission of Colorado, Order of Settlement, Decision No. C05-0049.

[63] "Risk factors," which are commonly used to measure the level of regulatory risk when calculating debt equivalency adders, range from 15% to 50% among procurements we are aware of. Washington allows a risk factor of 40% for take-or-pay contracts, and 15% for other PPAs. Puget Sound Energy, All-Source RFP Pre-Proposal Conference, February 11, 2004, Meeting Notes, as referenced in: GF Energy, 2005. In Louisiana, Entergy's use of a 50% risk factor was approved by the Commission. Potomac Economics. "Independent Monitoring of the Evaluation of Proposals for Entergy Long-term Supply-side Resources, Solid-Fuel Final Report," Exhibit DBP-2. Docket No. U-30192, 2007.

However, state policies continue to evolve both in terms of how to account for potential inferred financial impacts and the quantitative measure of such impacts. For example, after initially allowing use of inferred debt adders, California has recently precluded utilities from using such adders in its procurements, while recognizing the potential for recovery of potential inferred debt impacts in later rate hearings.[64] Commissions can also mitigate such risks by increasing assurances about PPA cost recovery, which will likely affect how rating agencies take PPAs into account in their evaluations.

6. *Economic Risk Mitigation Aspects of PPAs*

Under self-build proposals, regulators typically must make decisions about which of the utility's actual investment and operating costs are prudent, used and useful, and therefore recoverable from ratepayers. However, the timing of these decisions is sometimes out of synch with competitive procurement cycles. Therefore, there is a special challenge for procurement processes to deal with the potential situation in which the utility determines that its self-build proposal is more attractive for customers than any of the offers from the market, rejects offers from the market, and then proceeds in pursuit of its own plant.

Under a self-build proposal, it is not until much later on – after actual construction of the facility and in light of the actual costs incurred in doing so – that the utility takes its investment in plant to regulators to determine cost-recovery for the plant. By that time, the original offers from the market may be quite stale and may not reflect what was reasonably known at the time the decision was made to proceed with self-build proposal. The regulator will have to address what market or other information to use in considering the cost-effectiveness of the actual plant as built by the utility and whether the utility's actual costs were prudently incurred. In the end, the utility's self-build costs may turn out to be much higher than anticipated at the time the alternative offers from third parties were rejected.[65,66] (Similarly, performance of a self-build plant may end up

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[64] California Public Utility Commission, Opinion Adopting Pacific Gas and Electric Company's, Southern California Edison's, and San Diego Gas & Electric's Long-Term Procurement Plans, Decision 07-12-052, December 20, 2007.

[65] Not only in the past, but also in more recent instances, actual cost overruns for utility self-build facilities illustrate that these risks are real. The history of past nuclear plant cost overruns is well known in the electric industry. *See*, *for example,* Bonbright, James C. et al., *Principles of Public Utility Rates*, Public Utilities Reports Inc.: Arlington, VA, 1988, p. 257-8. More recently, self-build projects developed by Entergy in Louisiana and Duke in North Carolina have experienced similar cost increases. *See* National Economic Research Associates. "Competitive Electricity Markets: The Benefits for Customers and the Environment," prepared for the COMPETE Coalition, 2008, p. 14.

[66] It is also possible for self-build plants to end up costing the same or less than originally anticipated. A recent example of a utility self-build project which ended up with a lower cost (on a dollar-per-kilowatt basis) than originally expected is Sierra Pacific Power Company's new Tracy Combined Cycle Unit in Nevada. It was originally approved by regulators at a budget of $421 million for a 514-MW unit, and ended up costing that amount for a unit with a 541-MW unit; in effect, the cost went from $819/KW to $778/KW. Sierra Pacific Power Company, Application to Increase Annual Revenue Requirements, Before the Public Utility Commission of Nevada, Docket No. 07-12001, Application Volume 1, Page 2.

being lower than anticipated when it was reviewed.) Determining what portions of these higher costs will be borne by ratepayers will need to be determined by the commission at different points in the life of the investment. Thus, the self-build facility raises particular types of inherent ratepayer risks that generally do not exist for resources supplied under PPAs. While it is possible to impose the same economic discipline on self-build offers as that applied to offers from third parties – such as through contracts that hold the utility to the price and performance terms that it assumed in its evaluations of self-build and third party offers – it is not the norm to do so.

Therefore, PPAs can provide inherent benefits to consumers by shifting these risks to suppliers.[67] Consequently, evaluations should aim to capture differences in the financial risks associated with different types of proposed agreements (e.g., PPAs and self-build proposals) and differences arising from particular contractual terms, such as the use of pricing terms dependent on fuel indices. Failing to account for risk mitigation will inherently disadvantage offers from third-party suppliers (who must account for such risks when making binding offers and contractual commitments) relative to self-build proposals from utilities (which tend to have such risks at least partially mitigated by the fact that regulatory review is based on actual rather than anticipated costs).

Procurements generally do not consider these risk mitigation benefits when evaluating competing supply offers. Several approaches could address these risks. First, similar to adjustments for debt equivalency, quantitative adjustments for risk mitigation could be developed.[68] As with debt equivalency, empirical understanding of these risks is limited, although, in principal, adjustments reflecting historical variances between initial and final cost estimates could be developed. Such adjustments may be no less accurate (and potentially more accurate) than current debt equivalency adjustments. We are unaware of any procurements that have utilized such adjustments to capture risk mitigation benefits.

There are other alternatives proposed to adjust for risk mitigation. One approach mitigates a portion of the supplier's risk (whether the utility or a third party) by allowing payments to vary depending on the level of market indices that capture these risks. Examples include the use of a natural gas price index to capture fuel prices risks, and use of a construction/materials cost price index (e.g., for steel and other materials) to capture construction cost risks.[69] Such approaches, however, do not completely resolve

[67] Further, incentives to control costs may be improved by assigning these financial risks to suppliers, who bear the full burden of these risks, rather than utilities, who share these risks with consumers. However, assuming that these risk transfers are accurately captured, supplier and utility offers should reflect the potential gains from these improved incentives.

[68] Boston Pacific Company. "Getting the Best Deal for Electric Utility Customer, A Concise Guidebook for the Design, Implementation and Monitoring of Competitive Power Supply Solicitations," prepared for the Electric Power Supply Association, 2004, p. 16.

[69] For example, the PacifiCorp 2012 RFP allows 40% of capacity payments to be tied to market indices, and up to 25% to be tied to the Consumer Price Index and up to 15% to be tied to the Producer Price Index for Metals and Steel Products. PacifiCorp, Request for Proposals, Baseload Resources, April 5, 2007, p. 39.

the inherent differences in risks between PPAs, self-build proposals and other forms of agreement. For example, these approaches typically do not fully mitigate project-specific risk that can be particularly daunting for certain types of projects (e.g., large, capital-intensive baseload plants). In addition, by shifting risks back onto consumers, indexing of payments may be undesirable in terms of other policy goals related to rate stability. As discussed previously, another approach to closing the gap between PPA and self-build risks is to shift development and capital cost risks from consumers to the utility by requiring that the utility agree not to pursue cost recovery for increases in construction costs beyond initial estimates. Thus, the utility would bear the risk of cost increases, which would then need to be reflected in its self-build offer.

7. *Transmission*

The transmission impacts associated with particular incremental resource additions can vary considerably from one proposal to another. These transmission-related costs can include the costs of connecting the facility to the transmission network, changes in overall system productions costs arising from congestion on the transmission system introduced by the operation of the new facility, and any costs associated with upgrades on the transmission network needed to enable the new resource to qualify for network service.

In comparing the value of incremental supply offers to retail customers, utilities therefore must not only examine the direct costs to purchase power supply but also the indirect costs arising from the manner in which an offer interacts with the utility's system dispatch and the impact (if any) of the output from the proposed resource on power flows on the utility's transmission system. As part of this analysis, competitive solicitations typically must involve evaluation of any transmission-system upgrades needed to deliver the proposed resource(s) to target customers. The costs of congestion and/or transmission upgrades necessary to achieve deliverability are an important consideration in resource procurements.

In the context of competitive power procurements, there are two important concepts associated with a proposed resource's deliverability:

1. *Interconnection* – This refers to the transmission connection between the generation facility and the existing transmission network.

2. *Integration* – This refers to any changes to the transmission system that may be necessary to enable new generation resources to meet load requirements and meet relevant reliability standards.

The costs of interconnecting generating facilities are relatively predictable. A bidder may be able to develop its own rough estimates to interconnect its facilities to the grid.[70] Typically, competitive procurements require the developer of the generation resource to bear such interconnection costs.[71]

By contrast, the costs to integrate fully a new resource into a system are likely to vary dramatically across systems, and across particular regions or nodes within a system. The costs may also vary depending on whether the resource is intended to supply firm or interruptible power under a variety of system contingencies. Typically a bidder will not have the detailed technical information necessary to calculate integration costs. Complex modeling of the transmission and generation systems is needed to identify what facilities are needed and then to estimate their costs. For example, in some cases, adding a new facility may delay the need for a planned transmission facility, and in other cases, the new generating resource may hasten the need for transmission upgrades. In the end, cost estimates for both interconnection and system integration enhancements rely on studies and engineering specifications developed by transmission providers, with these studies themselves taking time and money to accomplish. Because the cost of such system enhancements may differ between competing offers in competitive procurements, utilities should aim to find efficient and timely ways to obtain estimates of these costs.

Procurement design for incremental resources therefore must address several key issues related to transmission costs:

- ***Identification of transmission-related costs to include in the review of alternative offers*** – What might seem like a straight-forward issue in theory typically turns out to be quite complicated in practice. On the one hand, it is clear that if incremental offers for generation resources have different implications for transmission system integration costs, then utilities seeking to understand which offer provides the best value to customers should look not only at the direct costs associated with the generation offers, but also take into account their indirect costs (e.g., transmission system upgrades.) This should be the goal, but there will be important technical issues that must be addressed to accomplish this objective in a way that dovetails well with other features of the

[70] Interconnection costs reflect the costs of the engineering and construction of transmission wires and other equipment necessary to connect new resources to the existing transmission network or to increase transmission capacity for re-powered facilities that will increase net output. Existing generation facilities or re-powered facilities not increasing net output typically do not incur any additional interconnection costs. The transmission company generally provides estimates of interconnection costs for all bids if bidders have not already obtained such estimates through prior requests for interconnection.

[71] Although there have been some allegations of bias in the interconnection cost estimates used to evaluate self-build or affiliate proposals, concerns about non-comparability of interconnection costs appear less serious than those related to integration costs. Further, it is likely easier for independent monitors to identify non-comparability for interconnection costs than for integration costs. (For example of such allegations, a report from the Colorado Public Utility Commission Staff noted that Public Service of Colorado estimated interconnection costs at $4.5 million for their self-build option while assessing interconnection costs of $60.5 million to other offers for similar coal-fired facilities. Staff of the Public Utilities Commission of the State of Colorado, "Report on Public Service Company of Colorado's 2003 Least-Cost Resource Plan," Volume 2, Docket No. 07M-147E, June 29, 2007, p. 26.)

procurement process. First, in procurements for new resources, some specific generating project proposals may not have advanced far enough in the development process to be captured in studies by the transmission provider. The depth of the information available about congestion impacts, system upgrades, and facility cost estimates thus may vary significantly across offers. The planning studies and detailed technical analyses of such transmission issues are typically conducted by the transmission provider and can be costly and take time to complete. Therefore, a utility should anticipate the need for planning studies in advance of a procurement, and may find it useful to ask for appropriate studies to be performed as part of the transmission provider's transmission planning process (under FERC's Order 890).[72] The results of such studies can assist the utility in developing proxy cost estimates for integrating certain types of facilities located in different areas on the system.

- ***Bidder information on transmission costs*** – Although transmission-system integration costs are often an important component of a utility's economic evaluation of bids, such costs may not be well known to prospective bidders prior to submission of their offers. Without such information, bidders may not have a good sense of whether their proposals stand a good chance of winning a procurement. Given this uncertainty, utilities and transmission companies should attempt to provide bidders with information that will provide guidance about the relative costs of integration across alternative locations. Analyses performed by transmission providers when undertaking planning studies and specific network impact studies provide a useful source of information for utilities in their evaluation of the costs of integrating new generation into the system. These public processes and their results can also provide insights to market participants about possible cost advantages or disadvantages of offers located in one area or another. In addition, such information will help to explain (in part) the outcomes of the utility's evaluation of how individual offers interact with the utility's current portfolio of resources. Using this or other available transmission information, utility RFP documents should assist bidders by identifying to the extent possible such things as: any favored delivery points given the existing configuration of loads and generation in the network; locational information about a benchmark resource;[73] or information about likely integration costs.[74]

[72] See, for example, FERC Order 890, Section V.B (Coordinated, Open and Transparent Planning), 2007, paragraphs 418-551; 18 CFR Parts 35 and 37 (Docket Nos. RM05-17-000 and RM05-25-000; Order No. 890) Preventing Undue Discrimination and Preference in Transmission Service (Issued February 16, 2007).

[73] For example, regulations in Florida require identification of details about the self-build option being pursued by the utility, including the proposed location. Such information is required to be accurate and any revisions to such information are to be provided to potential bidders in a timely fashion. Reliant Energy Power Generation, "Amended Complaint of Reliant Energy Power Generation, Inc. Against Florida Power and Light Company," Florida Docket 020175, May 17, 2002.

[74] For example, Georgia Power Company's 2010 RFP provided information on regions of the Southern Company's Control Area that are likely to have higher integration costs and more "difficultly meeting transmission firmness requirements." Georgia Power Company, 2010 Request for Proposals, March 22, 2006.

- ***Bidder assumptions about who pays for system integration costs for winning offers*** – In theory, the transmission-related costs associated with individual offers can be borne by either the bidder or the utility soliciting the offers. Most utility procurements require that bidders assume in their offers that they will absorb the costs to interconnect their facilities to the grid. But procurements for incremental resources have varied with regard to assumptions about for transmission upgrades needed to integrate the facility into the system. On the one hand, there are instances where procurements have required that bidders assume that they will directly have to absorb the costs of any incremental system upgrades associated with its project; in these instances, a reasonable bidder will construct a bid that allows for recovery of such costs as part of the purchase of power from the project. Other competitive procurements have incorporated a different assumption – that is, as long as a bidder's resource is located in or delivered into the utility's service area, the bidder should assume that it will not have to directly absorb system integration costs if the bidder's project is selected by the utility.[75] These two approaches can introduce quite different assumptions into the price of power supply bids. In the former type of bid, on-system transmission integration costs may be built into generation prices; in the latter, generation offer prices do not incorporate system integration costs and differences in transmission-cost implications of alternative offers are accounted for in the utility's evaluation of those offers. In the end, either way approach leads to a result in which the transmission costs associated with winning (and approved) offers will inevitably be born by consumers, whether it is through inclusion of such costs in suppliers' bids or through distribution utilities' charges to their retail customers to support transmission investment needed to deliver power to them. However, the size of these costs may not be the same under both circumstances. For example, suppliers facing the requirement that they pay for transmission system impacts, but with limited information useful to determining such costs, may add price premiums to their offers to account for such uncertainty.

- ***Transmission study timeliness and cost*** – Because transmission system planning studies can be time consuming, expensive and otherwise resource-intensive,[76] these studies have the potential to create a bottleneck in evaluation

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[75] Some procurements have attempted to level this playing field by treating all offers as though they have network status. For example, the Georgia Commission required Southern to treat all bidders as competeing network resources in its 2005 RFP. ("... in order to mitigate the relative size of Southern and to increase alternative supplies, the Commission required Southern to treat unaffiliated entities as if they are competing network resources in meeting load and load growth." Calpine Corporation, "Protest and Alternative Request for Hearing of Calpine Corporation", FERC Docket No. ER03-713-000, April 29, 2003.)

[76] The cost and time of a full system impact study may place real constraints on how these studies are used in the evaluation stage of a competitive procurement process. Most procurements rely upon a preliminary transmission analysis for early stages of the evaluation process, both to lower the cost the evaluation and complete these initial assessments in a timely fashion. Once the initial evaluation stage has identified a short-list of the most competitive bids, full system impacts studies are then performed for bids on this short-list. For example, see the Georgia Power 2009 RFP (Accion Group, "Report to the Georgia Public Service Commission on the Georgia Power Company 2009 RFP," p. 27.) Also, the Entergy Louisiana Little Gypsy 3

procedures unless care is taken by utilities to plan their requests to transmission providers in ways that support competitive procurements. The time required to complete such formal planning studies has led some utilities to develop less costly and quicker approaches to estimate the cost of system impacts and needed transmission investments for use in evaluating procurement supply offers.[77] Such approaches help to identify the relative cost implications (for transmission and dispatch) of various resource options within a reasonable time frame; and it reduces the number of formal studies that eventually need to go through the transmission provider's formal transmission planning studies and/or facility review processes.

- ***Comparability of transmission-related costs*** – Estimates of system integration costs should be developed in ways that do not introduce unfair or undue discrimination among offers from third-parties, affiliates and the utility's self-build proposal. The complexity and "black box" nature of system impacts studies raise many challenging issues for ensuring such comparability.[78] In situations where the utility's competitive procurement team is reviewing offers from third parties, the utility's affiliates and any self-build proposals from the utility itself, an independent evaluator should review the comparability of any methodologies and the basis for cost estimates prepared by the utility team to review the offers.

For some types of resources, such as wind power, procurements have also had to address the "chicken and egg" problem of coordinating the timing and commitment to large transmission investments necessary to interconnect and integrate new resources on to the grid. Wind resources typically require both large interconnection investments, due to their remote locations, and potentially large integration investments to avoid regulation and loop flow problems that may arise due to sudden power variability.[79]

The complexity of these various transmission-related issues suggests that competitive procurements should include clear ground rules about the transmission-related assumptions to be used in preparing all bids and evaluating all offers (including self-build proposals). As a result of the complexity of these transmission issues, oversight by independent monitors may be important to ensuring bidder confidence and enforcement of procurement rules.

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procurement (Potomac Economics, "Independent Monitoring of the Evaluation of Proposals for Entergy Long-term Supply-side Resources, Solid Fuel Final Report,", September 2007).

77 Some procurements have considered the use of initial preliminary estimates in later stages of evaluation should system impacts studies be delayed. For example, see Benson, 2007, p. 40.

78 *For example, see,* Accion Group, "Report of the Independent Evaluator, [Georgia Power] 2010 and 2011 RFPs, Re: Draft RFP Documents," November 21, 2005, p. 4.

79 *See, for example,* "Oregon Department of Energy's Reply Comments on Bidding Guidelines," Oregon Docket No. UM 1182, October 21, 2005. Also, see the approach adopted by the California ISO to support interconnection and integration of "energy resource areas," such as areas with the potential to develop wind resources. 119 FERC ¶ 61,061, Order Granting Petition for Declaratory Order, California Independent System Operator, Docket No. EL07-33-000 (Issued April 19, 2007).

8. *Other Non-price Criteria and Bid Requirements*

While some "non-price" price criteria, such as transmission impacts or certain financial risks, may be quantifiable in dollar terms, other non-price factors that impact the value of a competitive offer may be difficult to measure on such terms. Such "non-monetized" criteria may include factors such as development risk, contribution to the overall fuel diversity of the utility's portfolio, environmental benefits, and operational flexibility.

There is substantial variation across procurements in which non-price factors are considered, and which non-price factors should be introduced via non-monetary metrics or other subjective approaches. (Appendix D provides details on the criteria considered in selected competitive procurements and whether these criteria are evaluated in monetary or non-monetary terms.) Some procurements include few non-monetized criteria, while others include many. There are obvious but nonetheless difficult tradeoffs in reliance on many of these criteria. While non-monetized factors may reflect important policy or service objectives, they also may increase the subjectivity of evaluation outcomes and increase the opportunity for preferential treatment of the utility's self-build or affiliate offers.

The means by which non-monetized criteria are evaluated and compared also varies significantly. An important issue is whether non-monetized factors are used as threshold eligibility requirements that proposals must meet in order to proceed to further evaluation and possible selection. Because such threshold criteria serve to leave some offers outside the door while others are able to proceed, these criteria must be chosen with care. In practice, their use is generally limited to factors that are in some way essential to a proposal's success, such as technical requirements (e.g., location of the resource on the system) or minimum supplier credit-worthiness. Winnowing out potentially valuable offers from consideration because of non-essential considerations can undermine the goal of providing the "best" resource options to consumers. To the extent they are used, such eligibility criteria should be stated explicitly in RFP documents to ensure that suppliers have an opportunity to fulfill such criteria and/or determine that it is not worth expending resources to prepare a bid.

For offers meeting these eligibility requirements, the further assessment of non-monetized criteria can take many forms. These assessments may range from evaluations that explicitly score and weight identified criteria to those that simply list non-monetized criteria that will be considered by the utility using their discretion. These alternatives balance several factors. Explicit scoring and weighting provides transparency to bidders, independent monitors and commissions, but may lead to evaluations that constrain the utility's ability to exercise appropriate judgment about these non-monetized criteria. Choices made by firms every day reflect these types of judgments about non-monetized factors, similar to the types of judgments made by homeowners when choosing a construction contractor. While procurements that simply identify relevant non-monetized criteria provide evaluators with flexibility in how such factors are considered, however, they may provide the utility with a subtle and difficult-to-trace way to exert improper preferential treatment for or against certain supplies. For example, in some circumstances, bids have been eliminated in the initial review or short-list stage due to concerns about the viability of the resource given information on:

project schedules; engineering, finance and permitting status; credit-worthiness; and other considerations.[80] In particular where utility self-build proposals or affiliate offers are involved, regulators should scrutinize the use of non-monetized criteria and expect to rely on on-the-ground oversight from an independent monitor to help ensure that such criteria are not used to improperly exclude certain offers from consideration.

[80] For example, several offers in PacifiCorp's RFP that lead to a proposed self-build were eliminated due to such factors. Oliver, Wayne. "Direct Testimony of Wayne Oliver on Behalf of Division of Public Utilities," Docket No. 04-035-30, DPU Exhibit 2.0., September 27, 2004, p. 21-22.

VI. PROCUREMENT OF FULL REQUIREMENT SERVICE

A. OVERVIEW OF FRS SUPPLY PROCUREMENTS

Utilities in states with competition for retail generation service typically do not rely upon incremental resource procurements. Instead, these utilities generally procure so-called full-requirement service ("FRS") products. In these states, utilities retain certain service obligations to provide supply for certain retail customers and yet may have no (or insufficient) generation resources to supply these customers' needs. This is true in states where the utilities divested most if not all of their generation assets and long-term supply agreements as part of industry restructuring. In these states, commissions have typically developed policies affecting the design and implementation of FRS procurements, which often reflect requirements embedded in each state's electric industry restructuring legislation.

In FRS procurements, suppliers submit offers to provide all electricity services for a standardized block (slice, or share) of the distribution utility's customer load. By standardizing the components of FRS and the terms of FRS contracts, price becomes the only factor differentiating offers from potential suppliers. Thus, the utility selects the offers with the lowest prices, after identifying sufficient blocks to supply customers' demand requirements. In most cases, the utility is the contracting agent, and in effect passes through the cost of buying power supply from the selected FRS contractors.[81]

By eliminating subjectivity and complexity from the evaluation of offers, the price-only nature of FRS procurements provides many benefits. For example, in those FRS procurements involving highly structured auctions (such as New Jersey, described Box 3), minimum procedural safeguards are needed to protect against self-dealing; the safeguards relied up are an independent auction manager, code-of-conduct requirements, and various monitoring procedures to deter outright bid rigging. Because price is the only factor affecting the choice of winning offers (assuming all bidders have met eligibility requirements), the evaluation process leaves little opportunity for improper assessment of offers. Consequently, participation of unregulated generation affiliates does not generally require additional safeguards to protect against improper self-dealing.

[81] The particular components of these products vary across utility service areas depending on the particular products offered in wholesale markets administered by Regional Transmission Organizations, transmission tariffs, and state requirements on electric generators (e.g., renewable portfolio standards). In the case of New Jersey, for example, full requirements service includes fifteen products from various markets. There are some deviations from these generalizations. Some commissions have excluded certain products from FRS contracts due to pending regulations that increased the uncertainty of the associated costs for suppliers.

Box 3

New Jersey's Procurement of Full Requirements Service (or "Basic Generation Service")

As part of its restructuring legislation, New Jersey's major electric distribution utilities undertake competitive procurements for the provision of electricity services to customers that continue to take Basic Generation Service ("BGS") from the utility. Utilities procure BGS supply through auctions using a "descending-clock" mechanism. In this type of auction, the utility posts a price and suppliers submit offers for the share of the utility's customer load they are willing to supply at that price. If there are more offers for supply blocks than are needed, the auction manager lowers the price in succeeding rounds of bidding until bidders offer just enough power to satisfy the utility's load requirements. Binding agreements are signed shortly thereafter, which allows the bidders to develop financial positions to hedge the financial risks of their BGS supply contracts. Winning bidders must also post sufficient collateral to mitigate the risk of defaulting on their supply commitments to the utility. Auctions are held at the same time for all affected utilities in New Jersey, although each utility procures supply for its own customers. The rules for these auctions have been relatively consistent since the first auction in 2001.

Bidders must meet certain eligibility requirements, but do not need to own generation facilities. Suppliers are responsible for needed components of supply (including energy, baseload energy, capacity, renewable credits, ancillary services, and so forth). And it is up to the supplier to determine over time what mix of resources (and what combination of physical supply contracts or assets and financial arrangements) to rely upon to service the BGS supply contracts.

The auction starts with all potential bidders submitting indicative bids prior to the auction to help determine appropriate starting prices. The auction occurs over one to two days, with new rounds occurring at relatively frequent internals within the auction period. Various bidding rules are imposed to improve price discovery and mitigate against strategic manipulation intended to raise auction prices. For example, bidders that chose not to offer supply in one round are prohibited from bidding in subsequent rounds. A variety of supply blocks (for different customer classes (e.g., a commercial supply product) and for different utilities) are auctioned in parallel, and bidders are allowed to shift their bids between product auctions over the course of the auction, until it closes. Affiliates may offer supply into the BGS auctions.

Currently, three-year contracts are procured for one-third of each utility's load in each year. Pricing terms vary depending on the type of customer being supplied. Supply for residential and retail customers is set at a fixed price over the three-year contract, while supply for customers with loads exceeding certain thresholds is set at a price that varies by hour.

The process is overseen by an independent auction manager/monitor hired by the utilities. The auction manager must approve the auction results in order for them to be forwarded to the Board of Public Utilities ("BPU"). The BPU has two days to approve the results of the process. In total, the auction takes about six days from the time the auction is held to the time when contracts are signed and approved.

The design of FRS procurements also has important implications for the distribution of financial risks associated with providing supply. By requiring that each supplier construct its offers and then commit to arrange for and manage all aspects associated with supplying electricity for a share of the utility's entire customer load, the utility effectively shifts important financial risks from itself to the competitive suppliers. One type of risk is the portfolio risk associated with constructing whatever mix of short-, medium- and long-term financial and physical arrangements the supplier believes are necessary and appropriate to service the contract. Another type of risk is the volumetric risk that arises from uncertainty about the size of customer load; this risk is particularly sensitive to the migration of customers to and from the utility's service territory.

Experience with FRS procurements varies across states depending on the implementation of industry restructuring, and particularly the duration of transition rate caps. While some states (e.g., New Jersey, Maine, Massachusetts) have many years of experience with FRS procurements, many other states' experiences are significantly shorter, particularly where transition rate caps and associated supply contracts have limited supply procured through FRS procurements.[82] Despite this variation in experience, because of many common design elements across states, existing experience provides a good basis for developing lessons about FRS procurements.

Most FRS procurements follow a common format: first, information about FRS products, the procurement approach, and a procurement schedule is released to bidders in advance of the actual date when offers are to be submitted. Because of experience with past FRS procurements, few recent changes in rules or products between procurements, and the opportunity to ask clarifying questions, these procedures are generally well understood by bidders in advance of submitting their offers. Next, bidders submit offers in accordance with specified procedures. Utilities then select winning bids, and regulators generally approve results within a short period of time. As an example of an auction style of FRS procurement, Box 3 describes the basic elements of FRS procurements in New Jersey.

Some states with retail competition are undertaking or considering policy changes with potentially important implications for competitive procurements. For example, several states have undertaken or are considering requirements that utilities develop integrated resource plans to identify potential resource deficiencies.[83] Some options for addressing resource deficiencies potentially alter current reliance on FRS procurements for procuring supply. Box 4 summarizes some of the revisions being undertaken or considered in different states.

Because these changes may lead to increased reliance on incremental resource procurements, lessons from such procurements as used by vertically integrated utilities may be valuable for providing insights into design issues. These changes may also have implications for future FRS procurements. So far, the relatively simple structure of FRS procurements arises because utilities procure all customer supplies through these procurements. However, in the future, procurements processes will need to accommodate both of these activities. For example, a utility that is supplying peaking resources itself will also be procuring FRS products in some form. At a minimum, such

[82] In many states that restructured their electric industries to allow for retail competition, customer choice and encouragement of divestiture of utility assets, the transition periods involved situations where distribution utilities met their customers' supply requirements through initial long-term "transition supply" contracts. This was true, for example, of Illinois, Massachusetts, Pennsylvania, and Rhode Island, among others. The presence of these multi-year supply contracts accompanied by transition rate periods meant that distribution utilities did not need to procure other supplies for many years. As these contracts have expired with the end of transition rate caps, distribution utilities have had to rely on FRS procurements to procure all supply for their customer.

[83] Delmarva Power & Light Company's Delaware IRP Update, March 5, 2008. Delaware PSC Docket No. 07-20. Integrated Resource Plan for Connecticut, January 1, 2008.

changes may lead to a re-definition of the utility's need for supply beyond its own assets and agreements, may shift some volumetric risk back onto rate payers, and re-introduce certain portfolio management responsibilities to the utility.

Some elements of the design of FRS procurements can have important implications for their success in terms of achieving an efficient and timely process, encouraging supplier participation, and developing the best offers for consumers. We discuss these further below.

B. PRODUCT DEFINITION – DIFFERENT TYPES OF FULL REQUIREMENT SERVICE SUPPLY

How FRS supply products are defined is an important means by which regulators may influence the consequences of FRS procurements for ratepayers. The early FRS procurements often sought to procure all service for all customers through a single procurement, so that consumer rates tended over time to closely follow changes in wholesale market prices. In recent years, regulators in many states have attempted to mitigate the resulting rate volatility arising from FRS procurements in a number of ways.

One approach to mitigate price volatility is to increase the duration of full requirements contracts. Procuring supply through longer-term contracts (e.g., two or three years) reduces price volatility by reducing the frequency of power purchases. A second approach to mitigating volatility is to pool or average procurements over time by procuring only a portion of load in each auction. By staggering procurements, customer prices at any point in time are based on a blend or rolling average of prices from different points in time.[84] Finally, volatility can be mitigated through the pricing terms offered to customers. Supply agreements (and thereby customer rates) can be set based on flat, non-varying rates over the duration of the agreement, or designed to vary by hour, day, or season in a predictable fashion over the agreement's duration.

Regulators' decisions about mitigating price volatility often seek to balance potentially competing policy tradeoffs. On the one hand, reducing rate volatility may shield consumers from certain undesirable economic consequences. However, shielding consumers from price volatility may inadvertently slow the development of competitive retail markets in these retail access states, as well as preventing customers from seeing the true cost of supplying power. This latter effect blunts price signals that might otherwise better inform customer decisions about using electricity or reducing demand.[85]

[84] Mixing contracts of different duration allows a blending of long-term contracts that stabilize prices and shorter-term contracts that may create fewer stranded cost and cost recovery risks for the utility.

[85] In states where competitive retail options exist, customers can mitigate rate volatility, and thereby avoid facing current market prices in all hours, by contracting with competitive retail suppliers offering fixed price service. In this case, however, the choice is made by the consumer, rather than the regulator.

Box 4

Elements of Evolving Regulatory Frameworks in States with "Hybrid" Full Requirements Service Procurements

Utility participation in resource procurements – In Connecticut, new legislation requires that electric utilities obtain certain new generation resources. Connecticut Light and Power, and United Illuminating were required to submit a self-build proposal for new peaking capacity. Third party suppliers were also permitted to make offers for peaking capacity. The legislation specified that suppliers be compensated based on a traditional "cost plus" regulatory model. In Ohio, a recently enacted law (127 SB 221) preserves the right of customer choice previously established in the state and retains the utility's standard offer requirement. The law allows a utility to propose a market rate option ("MRO") under some circumstances (e.g., existence of forward price benchmarks, and an RTO with a market monitor having certain roles and responsibilities), or an "electric security plan" (that allows the utility to undertake its own generation investment). If approved by regulators, the MRO must use open competitive bidding for establishing the suppliers and prices of MRO service; the law sets forth findings the Commission must make in order to approve the results of the competitive solicitation.

Utility procurement of resource portfolio – In Delaware, Delmarva power was required by legislation to pursue long-term supply contracts as a part of an IRP process. Delmarva is now in the midst of procuring a portfolio of new peaking generation resources, wind power resources, demand-side management and energy efficiency programs, short- and long-term bilateral contracts, and market purchases. State agencies have recently issued rules on utility portfolio development and management, and the terms of individual procurements.

Long-term contracts – A number of states are considering or have allowed utilities to enter into long-term contracts to provide supply for their customers on standard offer service. In Maine, for example, regulators have directed utilities to enter into long-term contracts, with a particular focus on capacity resources. Massachusetts recently passed a new "Green Communities Act" (July 2008) with requirements that utilities enter into long-term contracts with renewable suppliers for up to 3 percent of the utility's load.

Government involvement in procurements – The recently enacted Illinois Power Agency Act (2007) calls for the formation of a state agency with the power to construct and operate power generation facilities, procure supply through contracts with market participants, and sell power "at cost" to customers. Retail service provided by the state power agency would not replace standard offer service provided by the utility, but would offer customers an "at cost" alternative to standard offer service and service offered by existing competitive retail suppliers.

Procurement of renewable and/or alternative energy attribute credits – Under policies adopted by New York regulators, the state uses a hybrid approach to implement its renewable portfolio standard requirements. Electricity customers pay for renewable energy credits through a non-bypassable payment on their utility bills. The funds collected are used by the New York State Energy Research and Development Authority ("NYSERDA") to purchase renewable energy credits ("RECs") from renewable power suppliers; a single-clearing price auction process is used to make awards and sign contracts for different quantities of RECS for different contractual durations. New York's utilities have recently been directed to pursue renewables more directly, as well. In Pennsylvania, utilities are responsible for compliance with the state's Alternative Energy Portfolio requirements. PECO Energy has been authorized to use a competitive process to procure and bank Alternative Energy Credits ("AECs").

As a result of these competing goals and particular customer attributes, regulators and utilities often design standard-offer products – and the procurement of supply for them – to meet the different needs of different customer classes. Products for residential and small commercial customers are typically designed to minimize price variation through use of overlapping, two- to three-year contracts with fixed prices. By contrast, products for larger customers (i.e., customers above some pre-determined load threshold) generally follow market prices through single, short-duration (e.g., three-month) contracts with prices that vary by month or hour. Regulators appear more willing to shield smaller customers from market volatility given the fewer number of competitive suppliers available to them and, potentially, other policy concerns. Appendix E provides examples of different types of FRS products currently being procured in different states.

Utilities and their regulators may choose to mitigate certain risks facing suppliers in order to encourage participation in FRS procurements and avoid high risk premiums associated with particular regulatory uncertainties. For example, multi-year contracts may create risks for suppliers when significant policy changes loom on the horizon, such as now may exist with climate change legislation, or the adoption of a new capacity market in the relevant Regional Transmission Organization region. Given such uncertainties, some states have eliminated certain products from those procured as a part of FRS procurements, including potential renewables requirements and capacity market products.[86] Some states have even attempted to limit supplier's volumetric risk by placing limits on the extent to which the supplier's load obligations can shift over time give potential customers' migration.[87]

C. PROCUREMENT APPROACH – AUCTION AND REQUESTS FOR PROPOSALS

FRS procurements have been implemented through either single-price auctions, such as the descending-price clock auctions used in New Jersey (described in Box 3), or RFPs with sealed bid offers. To date, descending-price clock auctions have been used in several states, most notably, Illinois in addition to New Jersey, while other states rely on sealed-bid RFPs.

Under a sealed-bid RFP, bidders provide a single, binding, sealed offer that specifies the quantity they are willing to supply and the price demanded to deliver that supply. Utilities select the lowest-cost supply from among these offers and the price paid to each supplier reflects that supplier's offer price ("pay-as-bid"). By contrast, under descending-price clock auctions, suppliers submit multiple offers until the market clears, and suppliers are all paid the same price (the "single clearing price".)

In principle, clock auctions produce lower prices by promoting price discovery through multiple rounds of bidding and eliciting bids that better reflect underlying economic

[86] For example, in the past, Maryland utilities have exempted suppliers from future renewables requirements and Massachusetts utilities have exempted suppliers from uplift and capacity requirements. Maryland Utilities, "Maryland Utilities' Request For Proposals for Full Requirements Wholesale Electric Power," Pre-bid Conference, December 12, 2006. *See also*, Competitive Procurement Survey Response from Massachusetts.

[87] For example, starting in June 2008, power (MW) supply obligations under Maryland utility FRS contracts are capped at a fixed quantity. Any increase in supply obligation beyond this cap as a result of customer migration or other factors is the responsibility of the utility. Maryland Utilities, 2006, p. 63-65.

costs.[88] Although they impose greater cost and complexity on administrators and market participants, the overall cost of implementing such auctions is likely to be modest relative to the total value of services procured in these auctions. While clock auctions provide better performance in principal than pay-as-bid RFPs, empirically demonstrating the magnitude of this benefit (if any) is difficult.

Under either type of procurements, bidders may be required to submit preliminary or "indicative" bids prior to the actual RFP or auction. These indicative bids may be used to determine initial prices in clock auctions and provide information to commissions useful for performing a preliminary assessment of likely market prices and the competitiveness of market response.

Such information may also be used as a part of procedures designed to protect against unanticipated, adverse procurement outcomes. For example, Maryland has developed a price anomaly procedure, under which higher-price bids may be rejected if average prices exceed thresholds designed to reflect current market conditions.[89] In other states, the commission has the authority to delay a procurement in the event of unforeseen events that may undesirably elevate market prices (e.g., hurricanes.)[90] Use of these procedures has potential implications for other aspects of procurement performance by, for example, increasing supplier uncertainty and leaving the utility out of compliance with other state regulations. For example, Massachusetts utilities would be unable to fulfill state requirements that they post rates in advance of providing service to customers if the result of a procurement were rejected and the utility had to rely entirely on spot markets to procure supply.[91]

D. OTHER ELEMENTS OF FULL REQUIREMENTS SERVICE DESIGN

1. *Bidder Eligibility and Collateral Requirements*

Because they are designed to select supplies on the basis of price alone, FRS procurements rely upon eligibility and collateral requirements to ensure that potential winning suppliers are able to fulfill their supply obligations. In particular, eligibility requirements generally require that suppliers demonstrate their credit-worthiness. In effect, these requirements attempt to ensure that all eligible suppliers have the means

[88] Cramton, Peter et al., "Auction Design for Standard Offer Service." Working Paper, Charles River Associates and Market Design, Inc, 1997.

[89] Under the price anomaly procedure, the commission's consultant, with input from its staff, develops a price anomaly threshold ("PAT"). If the load weighted average price from all winning bids exceeds this PAT, then the highest priced bids are dropped until the average price is at or below the PAT. Any deficiency in supply from dropping high priced offers is made up at subsequent or reserve procurements. Maryland Utilities, 2006.

[90] Public Service Commission of the State of Delaware, Order No. 7053.

[91] Competitive Procurement Survey Response from Massachusetts.

and incentives to deliver FRS supplies, along with insuring the utility and its customers against financial loss in the event of supplier default. In addition, suppliers are typically required to demonstrate their ability (and qualification) to participate in the relevant wholesale electricity markets needed to provide FRS supplies. Physical ownership of generation facilities is typically not a requirement.

Bidders generally are required to provide collateral in support of non-performance of the contract when offers are submitted. The level of collateral required is pre-determined based on the quantity of supply offered, and may also depend on the supplier's own credit-worthiness.[92] The forms of credit acceptable to utilities varies, with some utilities requiring cash or letters of credit, and others allowing bidders to propose alternate forms. Because fulfilling these requirements may be costly, it is important that collateral requirements are set to balance the utility's need to insure against default against the deterrence such requirements may have on supplier participation.

2. *Independent Monitors* [93]

Independent monitors may play several important roles in FRS procurements. First, they may review RFPs and related materials, oversee distribution of procurement information, and participate in public workshops to ensure that participants receive sufficient information to allow them to compete effectively. As information such as data on customer loads and migration is critical to suppliers' ability to submit competitive offers, ensuring that information is provided in a thorough and timely fashion is important to procurement success. Second, IMs typically monitor all procurement phases to ensure a fair and objective process. While the evaluation process in FRS procurements is fairly straightforward, IM oversight nonetheless helps to provide assurance to the utility, regulators, suppliers, and consumers that there are appropriate safeguards to prevent inappropriate bidding behavior or preferential treatment in selection. IMs, or other consultants hired by commission staff, may also provide an assessment of the procurement's competitiveness (e.g., number of bidders and quantity of supply bid), whether the procurement has occurred during a spike in wholesale market prices, or whether other "anomalous" events have adversely affected procurement outcomes.[94] The monitor may provide feedback on potential modifications

[92] For example, see, Maine Public Utilities Commission, "Request for Proposals to Provide Standard Offer Service to Central Maine Power Company's Residential and Small Commercial Customers," October 9, 2007.

[93] In an FRS procurement in which price is the only factor used in selecting bids, the independent monitor has sometimes been called an "independent auction manager" or an "independent evaluator." Although there are important nuanced differences among their functions, the essential feature is the involvement of a party who is neither an employee of the utility nor of the regulatory agency, with specific responsibilities relating to the competitive procurement. In Illinois' FRS auctions, the Auction Manager was responsible for designing and implementing the descending clock auction on behalf of the utilities. Her responsibilities included communications with bidders, conduct of the auction, monitoring the status of offer prices and participation, identifying the award group, and reporting to the Illinois Commerce Commission. Thus her role included monitoring the process, managing the auction, and evaluating the process and its results.

[94] Maryland Utilities, 2006; Public Service Commission of the State of Delaware, Order No. 7053.

to procurement procedures. In some cases (e.g., Illinois), the auctions were actually run, or managed, by the independent monitor (in this case, called the auction manager, selected by the utility).

Use of IMs in FRS procurements varies across states. In some states, procurements are reviewed by IMs that provide formal reports on procurement results to state commissions.[95] Other states do not use IMs and rely on oversight provided by the PUC to ensure the integrity of the procurement process.[96]

3. *Timing and Commission Approvals*

Procurement timing is particularly important for creating positive incentives for supplier participation and avoiding additional costs that may raise the prices of supplier bids. FRS procurements generally aim to minimize the time between submission of bids and awarding of contracts. This serves not only to minimize suppliers' financial risks associated with potential changes in market conditions that may occur after they submit their bids, but also to minimize the risk premium that suppliers would likely include in their offer to cover their exposure to these market risks. Because of the price-only nature of FRS procurement, evaluation of offers by utilities and approval of results by commissions can generally be competed quite quickly. All FRS-procurement states that we reviewed, with the exception of Maine, issued finalized procurement decisions within a five day period, and some finalized these decisions in as little as one day.

4. *Confidentiality*

Policies to protect the confidentiality of bidder information reflect a balance between (a) the benefits of transparency about the market's performance, and (b) protection of valuable and commercially sensitive bidder information. Commission policies on release of bid information typically involves bidder identities, quantities of offers (bids amounts), and the price level of winning bids.

Supplying actual bid information from the bidding rounds themselves raises a number of concerns. First, such information may reveal valuable information about bidding strategies. Second, such information may raise suppliers' costs of hedging the financial risks to supply FRS, and thereby the price of their FRS offers, by alerting financial market participants to their need for financial hedges. Potentially adverse consequences of these policies can often be mitigated through careful design. For example, release of information about winning bidders can be delayed to avoid raising the costs of financial transactions made after securing the FRS contract. In practice, policies regarding release of supplier information vary across utilities. For example, Delaware utilities only release information from its RFP procurements that reveal averaged bid prices and bid

[95] For example, Delaware, Maryland, New Jersey, and Washington, D.C.

[96] For example, Maine and Massachusetts.

ranges, while New Jersey utilities release information on market-clearing prices and winning bidders for each utility.[97]

[97] Response to Survey by Janis Dillard, Delaware PSC; "The 2006 BGS Auction Results," <http://www.bgs-auction.com/documents/2006_BGS_Auction_Results.pdf>.

VII. CONCLUSION

Competitive procurements for retail electricity supply have been used for many years in different states. More than forty percent of the states now rely on formal policies and rules for procurements, while regulators in many other states encourage use of competitive procurements by utilities in determining which resources to add to their mix of retail supply.

Where regulators have committed to relying upon competitive procurement approaches as a means to help identify the "best" resources needed to meet the needs of the utility's customers, the process should be designed and implemented so that it reflects the following criteria (and is generally viewed as being consistent with them):

- fair and objective;
- designed to encourage a robust competitive responses from market participants with creative responses from the market;
- based on evaluations that incorporate all appropriate and relevant price and non-price factors;
- efficient, with a timely selection process; and
- supported by regulatory actions that positively reinforce the commission's commitment to the other criteria.

While the use and design of procurements continues to evolve, there is a growing body of experience that provides a relatively clear set of issues that commissions and utilities should consider when they design competitive procurements to suit the industry structure and regulatory norms in their states. The checklists (in Tables 2 and 3 in the Executive Summary) and discussions of individual issues provided in this report lay out regulators' key decisions and options for the design of competitive procurements, the tradeoffs they must assess when choosing among these options, and the other lessons learned from past procurement experience.

While past experience provides valuable lessons for the design of future procurements, there are still many issues that require further development as regulators consider expanding the use of competitive procurements and using these procurements to develop the types of new resources that will likely be needed to meet future electricity needs in a manner consistent with other environmental and policy objectives. Notable among these issues are how regulators will incorporate the efficiency benefits of market forces in situations where capital-intensive resources and advanced technologies are needed to satisfy such long-term electricity requirements in a carbon-constrained economy. This merits continued attention from regulators and members of the industry.

APPENDIX A – INDEPENDENT MONITOR ACTIVITIES AND ROLES

The range of potential activities in which an IM might participate is extremely broad, spanning from the initial stages of procurement design to its final approval. In these interactions, the IM may assist commission staff or perform independent monitoring in the following areas:[98]

- Review and comment on completeness of proposed RFP materials and conformance with relevant requirements;
- Review and comment on proposed evaluation methods and assumptions;[99]
- Oversee written and verbal communications between the commission, its staff, potential bidders, and the utility (including its evaluation teams, transmission evaluation teams, and unregulated generation affiliates);
- Monitor and in some cases, moderate utility public workshops;
- Identify and assist in the resolution of potential disputes arising between parties involved in the procurement;[100]
- Provide feedback to the utility and commission on different elements of the procurement process;
- Validate utility self-build (prior to bid submission);[101]
- Review and validation of models and assumptions used in evaluating offers;
- Management of submitted offers, including initial review of submitted offers and "blinding" of offers in conformance with relevant requirements;
- Oversee of the utility's evaluation process;
- Independently evaluate submitted offers;
- Independently assess portfolios of offers according to broader planning goals;[102]
- Oversee negotiations with bidders; and
- Report on procurement process, results, and lessons learned to regulators.

[98] Other states providing detail on IM roles include Georgia (Georgia Code 515-3-4-.04)

[99] Utah Administrative Code, R746-420 requires such reviews, and procurements in Oregon have included such reviews. For example, *see* Boston Pacific Company and Accion Group, "The Oregon Independent Evaluator's Assessment of PacifiCorp's 2012 RFP Design," April 13, 2007.

[100] Utah Administrative Code, R746-420.

[101] Utah Administrative Code, R746-420.

[102] Public Utilities Commission of Colorado, Emergency Rules Amending the Commission's Electric Resource Planning Rules, Decision No. C07-0829, September 19, 2007.

APPENDIX B – CREDIT REQUIREMENTS

This appendix provides additional details on several aspects of how credit requirements are treated in competitive procurements, including:

- Rationales for the level of credit guarantees and/or collateral requirements;
- Means of reducing the cost of credit requirements; and
- A summary of credit requirements in illustrative procurements.

THE LEVEL OF GUARANTY OR COLLATERAL REQUIREMENTS

Financial guaranty or collateral requirements should be related to the actual financial consequences to utilities of suppliers' failure to perform under the terms of the contract. The risk of non-performance arises because of the potential for supplier bankruptcy or default, and the potential that it may not be in the supplier's financial interest to fulfill the terms of the contract. PPA agreements typically impose penalties on suppliers in the event that they cannot (or do not have sufficient incentive to) fulfill agreement terms, and provide financial compensation to the utility for the potentially higher cost of replacing lost power. To ensure that suppliers have sufficient financial resources to fulfill these terms, they are required to provide a financial guarantee that such funds are available.

(While less often the focus of scrutiny in procurements, some suppliers may seek to require that utilities (as buyers) put up some form of financial assurances that the utility will also perform under the terms of the contract. Reasons of commercial symmetry and fairness may warrant such reciprocal financial assurances, which may include conditions (e.g., a utility credit rating falling below a particular point) under which the utility needs to post forms of financial guaranty or credit to support their performance under the contract.)

Collateral requirements for power suppliers should reflect the likelihood that they will fail to perform and the financial consequences for the utility in the event of the seller's non-performance. Estimating the financial cost of non-performance will depend on many factors, such as the market alternatives available for replacing lost power, the type of supply being replaced (e.g., peaking or baseload), the value of the contract that remains to be fulfilled, and likely payments received through litigation of the contract. Some of these risks can be directly addressed in the terms of the contract (e.g., size of penalties for non-performance), with collateral in place to support the agreement.

In some procurements, bidders have questioned the level of credit requirements as unrelated to the actual non-performance risks facing utilities.[103] Regulators should attempt

[103] *For example, see* Louisiana Public Service Commission Staff, "Preliminary Comments of the LPSC Staff on the Draft RFP," Southwestern Electric Power Company, 2005 RFP for Intermediate and Long-term Resources, p. 3, 8-9.

to gauge whether the particular level of credit requirements is warranted or are so strict as to inappropriately stifle a robust level of participation from the market. The implication of credit requirements on supplier cost structures is not particularly well understood. For example, alternative assessments of impact of credit requirements on total project costs for recent California procurements suggested that such requirements raised costs as much as nine percent and as little as two percent.[104]

The level of financial guarantee necessary to address the risk of non-performance may change over the course of the procurement and the term of the contract. For example, during the bidding and evaluation phase of an incremental resource procurement, utilities may face some risk that a supplier's offer is not sufficiently developed and financed to be credible. Such offers may lead to unnecessary administrative costs and potential failures to develop resources in a timely fashion if they lead to procurement delays. Utilities often require a bid deposit or fee when offers are initially submitted, and then impose additional requirements for offers that are selected for the short-list. Regulators should be aware that initial bid deposits can act as a barrier to entry for certain suppliers – some of whom may submit desirable offers in certain procurements, such as those for demand side management services or renewable resources.[105]

Suppliers may also be required to post financial security during the time between the awarding of the contract and the time when delivery begins. Such requirements may be needed in the event that facilities under development do not meet contracted schedules, if the project defaults, or if the facility does not meet technical specifications (e.g., heat rate guarantee, availability levels, or emissions rate). During the period when suppliers are obligated to deliver power, many solicitations use a mark-to-market approach to set collateral requirements, in which the amount of required collateral changes in proportion to the utility's expected financial loss if it needed to obtain replacement power. However, the actual procedures by which mark-to-market approaches are implemented vary substantially across procurements.[106] Additionally, contract provisions allowing for penalties in the event of poor supplier performance (e.g., availability below acceptable target levels) may be able to address directly various risks, so that collateral can be focused more directly on default risk.

MEANS OF REDUCING THE COST OF CREDIT REQUIREMENTS

If credit protections are sought, procurement design should attempt to minimize their economic costs to bidders, while still providing adequate assurance to buyers. A way to minimize the cost of credit requirements on suppliers (and potentially on the resulting cost

[104] See reference to estimates reported by Starwood, Caithness and Black & Veatch in: Aspen Environmental Group and Sentech, 2007, p. 13.

[105] KEMA reports that short-list deposits for proxy projects in California renewables RFPs were $300,000 in three of ten RFPs reviewed and over $1.5 million in another. KEMA, 2006, p. 10.

[106] KEMA, 2006, p. 6.

of the winning supply) is for the utility to allow some flexibility to suppliers in how credit requirements are met.

Traditional means for providing credit include letters of credit from large, investment-grade financial institutions or financial guaranty from a credit-worthy entity, such as the parent company of the entity offering supply. These forms of security provide the procuring utility with a liquid source of funds that can be immediately drawn upon in the event of non-performance or default. However, the cost of obtaining and maintaining letters of credit may be high for developers. There may be situations where parent companies' desire to avoid providing additional finance beyond the equity typically included in such projects acts as a barrier to a supplier's participation in the procurement. Regulators should monitor the credit requirements placed on suppliers by utilities to assure themselves that the level and terms of the financial guarantees are appropriate to the risks involved in various stages of the process.

Recognizing the need for flexibility, other approaches have been used and are under development in an effort to provide lower-cost means of providing financial assurances to utilities. One approach is to provide the utility with a claim to project-specific assets, such as subordinate liens, in which the utility is granted rights as a creditor in the event of bankruptcy or default. Similarly, utilities may be granted rights to payments associated with plant equipment warranties or project insurance policies. The utility may receive step-in rights, in which it has the ability to take over project development in the event of developer default.[107] Suppliers may also provide an exclusivity guarantee to prevent it from selling to other parties. Because the value of many of these claims depend on market conditions at the time of non-performance, determining the financial value of the security provided by these claims may be more difficult than more traditional lines of credit or guaranties.[108] Other approaches are also being considered, such as securitizing specific agreement credit risks across multiple agreements, power supply clearinghouses or state operated risk pools.[109]

[107] Aspen Environmental Group and Sentech, 2007, p. 17.

[108] Comments by Southern California Edison in: Aspen Environmental Group and Sentech, Inc., 2007, p. 15.

[109] For example, *see* Ghosh, Partho S., "MMC Presentation to Electricity Committee Workshop on Lowering the Effective Cost of Capital for Generation Projects," June 27, 2006; references to MMC comments in: Aspen Environmental Group and Sentech, 2007, p. 17-18, 28, 33-34.

Table B1 – Credit Requirements From Selected Procurements			
RFP	**Timing of Credit Requirements (after short-list; during construction; during operation)**	**Allowed Forms of Credit**	**Credit Requirement Amount**
Southern California Edison 2006 RFO (All Source)	• Development security from effective date (regulatory and contract approvals) to beginning of delivery • Delivery security	Unspecified	• Development security of $109.6/kW (fast track) and $54.8/kW (standard track) • Delivery security required for amounts above unsecured credit to cover mark-to-market exposure over a 24- or 48-month period. (Only investment grade bidders eligible for unsecured credit.) • Seller grants secondary liens to SCE
Pacific Gas & Electric 2005 (New Generation Resources)	• Proposal fee • Selection security (upon request for CPUC approval) • Development security • Operating security	Unspecified	• Proposal fee: $5/kW • Selection security: $10/ kW • Development security: $61/ kW • Operation security: mark-to-market (either a 2- or 5-year window, depending on time to replace generation), and collateral threshold
Georgia Power Company and Savannah Electric Company 2009 RFP	Unspecified, but ability to meet credit standards or security requirements must be demonstrated in offer	Credit requirements may be met through: 1) Seller net worth threshold; 2) Guaranty from entity meeting net worth threshold; 3) Investment grade credit rating based on utility evaluation; or 4) Collateral sufficient to cover potential damages resulting from seller default (levels are not specified). Unless a successful bidder (or its guarantor) is rated at least one notch above investment grade, then 50% of such bidder's security collateral must be in the form of cash or a letter of credit.	Credit requirements standards can be met through either demonstration of credit-worthiness (with specific Allowed Forms of Credit) or posting of collateral sufficient to cover necessary damages resulting from default
Progress Energy Florida (2003)	• Development security starting 30 days after contract signing • Operating security starting 30 days prior to planned operation date for the duration of the contract	Letter of credit, cash, or U.S. bonds held in escrow	• Development security starting at $20/ kW and rising to $50/kW (at 12 months before commercial operation) • Initial operation security of $10/kW, $20/kW after 5 years, and $30/kW after 10 years

Table B1 – Credit Requirements From Selected Procurements			
RFP	**Timing of Credit Requirements (after short-list; during construction; during operation)**	**Allowed Forms of Credit**	**Credit Requirement Amount**
Entergy 2006 RFP for Long-Term Supply-Side Resources	• Letter of intent security • Performance collateral upon execution of agreement	• Traditional forms of collateral and non-traditional forms on a case-by-case basis (e.g., lien on assets and step-in rights)	• Letter of intent security of $2 million letter of credit • Performance collateral: $200 per kW for solid fuel; $100 per kW for CCGT • Entergy determines amount of uncollateralized exposure based on the bidder's credit rating (up to $100 million for AAA to A-)
Northwestern Energy (Issued July 2, 2004)	Unspecified	• Demonstration of investment grade credit rating • Acceptable performance assurance, including letter of credit, guaranty from parent company, or cash	Unspecified
PacifiCorp's 2012 RFP	Security starting on the date of PUC contract approval or execution by parties (starting at 10% of full credit and rising to 100% in 2 years, with full credit due when financing secured)	• On-going: letters of credit, guaranties, cash or other collateral • Asset-back agreements "must" backup agreement with the resource through certain options, including step-in rights, second lien, leverage limitations, and other financial covenants • Initial (10%) security must be posted with letter of credit or cash unless 100% of security is posted at effective date	• Credit requirements reflect PacifiCorp's market exposure given type of agreement, agreement term, and other factors • Credit matrix identifies security requirement based on type of resource, size of resource, and the year the resource is expected to be operational • PacifiCorp permits some uncollateralized supplier exposure depending on seller's credit rating and the type of resource
PacifiCorp's 2009 RFP	Security starting on the date of PUC contract approval or execution by parties (starting at 10% of full credit and rising to 100% in 2 years)	Acceptable "credit assurances" are unspecified (letter of credit is acceptable)	• Credit matrix based on type of resource, size of resource, and the year the resource is expected to be operational • PacifiCorp permits some uncollateralized supplier exposure depending on seller's credit rating and the type of resource
Puget Sound Energy 2008 All Source RFP	Unspecified	Unspecified	May be required to post collateral absent demonstration of credit-worthy status (BB+ or better) or guaranty from credit-worthy parent company

Sources:

[1] Southern California Edison, RFO for New Generation Resources, Transmittal Letter, August 14, 2006, pp. 16-17.

[2] [Pacific Gas & Electric] KEMA, Inc., "The Cost of Credit: A Review of Credit Requirements in Western Energy Procurement," prepared for the California Energy Commission, CEC-300-2006-014, 2006.

[3] Georgia Power Company and Savannah Electric Company 2009 RFP (Draft), July 5, 2005, pp. 10-11.

[4] [Progress Energy Florida] Merrimack Energy Group, Inc., "Report of the Independent Evaluator Regarding PacifiCorp's 2012 Request for Proposals for Base Load Resources," Utah PSC Docket 0503547, August 30, 2006, pp. 2-3.

[5] [Enetergy] Merrimack Energy Group, 2006, pp. 9-10.

[6] Northwestern Energy RFP Issues July 2, 2004, p. 12.

[7] PacifiCorp 2009 RFP for Flexible Resources (Draft), Responses due December 1, 2005, pp. 15-16.

[8] PacifiCorp 2012 Credit Security Requirements Methodology Overview, pp. 1-5.

[9] Puget Sound Energy 2008 All Source RFP, January 2008, pp. 10-11.

APPENDIX C – DEBT EQUIVALENCY

The report previously described the two most common methods for addressing the financial impact of the debt-like commitments taken on by utilities when entering into power purchase agreements. These two methods address these issues either

(a) through the cost-of-capital and capital structure phases of general rates cases; and/or

(b) through use of adders to third-party offers that introduce an economic penalty on third-part offers relative to utility self-build proposals.

Because regulators are more familiar with addressing a variety of risk issues faced by utilities in cost-of-capital and capital structure issues in general rate case proceedings, in this appendix we focus on the latter approach; that is, methods used to develop adders to account for debt-equivalency affects in the context of competitive procurement proceedings.

The methods used to estimate inferred debt "adders" generally draw upon the explicit balance sheet adjustments made by credit ratings agencies to take into account a utility's relative default risk as a result of its contractual financial obligations, including PPAs.[110] Under these methods, the level of inferred debt depends on the size of fixed payments assumed in these contracts and a risk factor that reflects the likelihood of full cost recovery of these PPA costs given the specific regulatory and legislative conditions affecting recovery. The risk factors used by credit agencies may depend on the relevant state commission's "reputation" regarding cost recovery and specific aspects of state's utility regulation, such as whether there is a mechanism for automatic rate adjustment, whether the Commission has approved the RFPs or the selection of offers, and whether legislative requirements are supportive of cost recovery.[111]

When considering whether to allow utilities to use some form of risk-adjustment adder to compare contracts against self-build options in the context of competitive procurements, commissions should be mindful of what they already know in general – that is, that the inferred debt adjustment made by credit agencies is not the only impact on credit ratings from a utility signing a PPA. In fact, Standard & Poor's has explicitly indicated that it accounts for many factors when assessing utility credit risk, including other factors that may affect the choice between alternative types of supply agreements. For example, credit agencies would recognize the reduced utility exposure to commission prudence determination that would arise from entering into a PPA rather than adding additional

[110] For example, *see* Standard & Poor's, 2007.

[111] For example, *see* Standard & Poor's, 2007.

capital to the utility's rate base.[112] Because inferred debt calculations do not account for these factors, regulators should be careful not to infer that risk factors account for the *net* impact of PPAs on either the utility's cost of capital (via its credit status), let alone the final financial risks to consumers. Unfortunately, there is relatively little empirical analysis to shed light on the net impact of PPAs on utility's cost of capital.[113]

Because of these factors, while most states that include debt equivalency "adders" utilize the same basic methodologies, the specific risk factors that commissions have used range from 15% to 50% across procurements. For example, Washington allows a risk factor of 40% for take-or-pay contracts, and 15% for other PPAs, and, in Louisiana, Entergy procurements use of a risk factor of 50%.

[112] "That said, PPAs also benefit utilities that enter into contracts with supplier because PPAs will typically shift various risks to the suppliers, such as construction risk and most of the operating risk." Standard & Poor's 2007).

[113] What research has been done suggests that PPAs have little effect on a utility's cost of capital, while utility self-builds raise it. However, various limitations to this study caution against any broad conclusions from its results, the results do suggest that the importance of understanding the risk tradeoffs posed by alternative agreement forms to selecting the most desirable supply alternatives. Kahn, Edward et al., "Impact of power purchased from non-utilities on the utility cost of capital," *Utilities Policy* 5(1): 3-11, 1995.

APPENDIX D – EVALUATION OF PRICE AND NON-PRICE FACTORS

Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	**State**	**RFP**	**Monetized**	**Non-monetized**
[1]	UT	PacifiCorp 2009	Price, based on ratio of bid price to projected price (60%)[114]: (for a ratio of [x], the bid gets [y] points:) • Ratio < or =l to 80%: 100% • Ratio > 80%, but < 120%: 100% times ratio • Ratio > or = 120%: 0%	Non-price factors will be weighted (40%): • Flexibility of resource dispatch: day-ahead and adjustment: 20%; or only day-ahead: 10% • Exceptions to any pro forma agreements: 10% • Environmental attributes relative to the resource, if applicable: 10%
[2]	OR	PacifiCorp 2012	Price, based on ratio of bid price to projected price (70%)[115]: • Ratio < or = to 80% of adjusted price curves: 100% • Ratio > 80%, but < 120%: 100% times ratio • Ratio > or = 120%: 0%	Nonprice factors will be weighted (30%): • Development, construction, operational experience: 10%[116] • Compliance with pro forma agreements submitted with proposal: 10% [117] • Site control and permitting: 10%
[3]	OK	Oklahoma Gas & Electric Co. 2008-2010 RFP	Price factor (60%), reflecting: • Capacity charge • Energy charge • Start-up charge • Transmission system impact	• Bidder's proposed changes to Model PPA: 10% • SPP RTO market risk cost allocation: 15% [118] • Quality of output: 15% - Dispatchability/scheduling - Reliability/availability - Operating profile/characteristics

[114] Total score reflects score on price ratio multiplied by weight, for example if ratio = 90%, score = (90*0.6) = 54.

[115] Total score reflects score on price ratio multiplied by weight, for example if ratio = 90%, score = (90*0.7) = 63.

[116] One percent point for each project the bidder has previously developed, constructed and/or operated, with partial points awarded for partial experience.

[117] Modifications to pro forma agreements could result in a reduction in the bidders score (out of 10%) if those modifications resulted in a material shifts in risk or cost from the bidder to the utility. This process and percentage application per section within the pro formas was to be validated by the IE.

[118] SPP/RTO Market criteria was intended to relates to the bidder's proposed methodology for the sharing or allocation of market benefits and risks between bidder and OG&E that may arise from changes to SPP RTO market rules.

Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	**State**	**RFP**	**Monetized**	**Non-monetized**
[4]	AZ	Arizona Public Service Commission 2007 RFP for Renewables	Quantitative[119]: Respondent Bid Price plus Additional Costs is compared against Market Cost of Comparable Conventional Generation[120]	• Financial risk • Regulatory risk • Counterparty credit risk • Transmission risk • Operations risk • Project development risk
[5]	MT	NWE 2004 RFP	Proposal price and value, including: • Costs/benefits of transmission • Value of dispatchability • Firmness of products • Ability to remarket energy • Value of points of delivery • Ancillary services value • Costs of resource integration	• Development and performance risk (2nd most important factor) • Environmental factors (3rd most important factor)
[6]	FL	Progress Energy 2007 RFP	• All costs, as reflected in 30 year optimization analyses	Minimum bidder eligibility requirements: • Environmental • Engineering and design • Fuel supply and transportation plan • Project financial viability • Project management plan Technical criteria:[121] • Development feasibility • Project value • Operational quality

[119] Respondents were advised that price would be a major factor in APS' evaluation, but APS will consider other quantitative and qualitative risk factors.

[120] "Respondent Bid Price" referred to the amount APS would pay to the respondent. "Additional Costs" were costs that are needed to incorporate the renewable resources into APS' system, including additional interconnection costs, system integration costs, and costs associated with imputed debt (for PPA proposals). "Market costs of conventional generation" were to reflect the utility's energy and capacity cost of producing or procuring incremental electricity from a conventional resource.

[121] "Development feasibility" were to reflect the bidder's ability to meet development schedules, such as permitting certainty, financial viability, commercial operation date certainty, and bidder experience. "Project value" were to reflect the project's cost and flexibility, including acceptance of key terms and conditions, fuel supply and transportation reliability, reliability impact, and flexibility provisions. "Operational quality" was to measure the proposed unit's flexibility to respond to changes in system demand, including minimum load, start time, ramp rate, max starts/year, minimum run-time/down-time constraint, and annual operating hour limit.

Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	**State**	**RFP**	**Monetized**	**Non-monetized**
[7]	WA	Puget Sound Energy (PSE)	• Resource cost • Transmission • Portfolio cost impact[122] • Capital structure impacts • Guarantees and security[123]	• Timing • Resource match to monthly need • Operational flexibility • Performance within utility's own resource mix/portfolio • Status and schedule • Price volatility • Resource flexibility and stability • Resource technology • Long-term flexibility • Project risk • Impact on PSE's overall risk[124] • Environmental & permitting risk • Ability to deliver as proposed • Status of transmission right • Managerial control • Security & control • Federal regulatory approvals • Environmental impacts • Resource location • Community impacts • Future exposure to taxes and/or environmental regulation
[8]	LA	Entergy Fall 2006 RFP	Individual and portfolio costs, as estimated by a production cost model	Non-quantifiable aspects of: • Transmission • Fuel cost and availability Portfolio design criteria, including: • Product category supply cost ranking • Maximum total resource objective • Regional dispersion • Product category needs • Mix of product terms

[122] Portfolio cost impacts taken into consideration for proposals that make the preliminary shortlist.

[123] PSE took into consideration credit information provided by the bidder to determine whether PSE would requires any additional guarantees or credit support, and include the estimated costs of providing such guarantees or credit support to the bidders proposed offer terms.

[124] The impact on PSE's overall risk position was considered for proposals making the preliminary shortlist.

Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	**State**	**RFP**	**Monetized**	**Non-monetized**
[9]	GA	Georgia Power Company and Savannah Electric 2009 RFP	Fixed costs: • Capacity cost payment • Fixed O&M payment • Cost due to inferred debt from PPA[125] • Startup costs • Fuel pipeline costs, including the estimated costs for adequate firm natural gas transportation and natural gas storage Variable generation costs: • Fuel cost • Variable O&M • Proposal dispatch characteristics Transmission costs: • Integration costs • The increase (or decrease) in transmission system energy losses	Development schedule: • Reasonableness • Contingencies • Current developmental status Resource schedule and dispatch flexibility: • Lead time for dispatch schedules[126] • Ability to change schedules hourly/daily[121] • Quick start capability or curtailment • Minimum schedule and downtime • Minimum energy take[121] • Response to emergencies • Dispatchability[121] • AGC capability Fuel: • Type of fuel • Risk of fuel supply interruption • Price risk Environmental: • NOx. VOC and SO^2 compliance strategy • Toxic release inventory • Future permitting restrictions • Water requirements Proposed PPA changes Transmission: • Impact on transmission interface capability[121] • Transmission delivery risk[121] • Voltage control[121] • Other grid impacts[121]

[125] The equity cost of lease reflects an estimate of the "debt equivalency" impacts as measured by either the PPA's balance sheet impact on the balance sheet (in the case of capital lease) or the capital structure adjustment necessary to cover the imputed debt burden (in the case of an operating lease).

[126] Where possible, this might be converted into an explicit price factor.

Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	**State**	**RFP**	**Monetized**	**Non-monetized**
[10]	CA	Southern California Edison 2006 RFO	• Market assessment: the market value of the benefits contained in each offer versus its costs[127] • Transmission impact: cost of network upgrades • Debt equivalence as additional cost • Environmental: greenhouse gas emissions adder ($8 per ton of CO^2) • Credit: ability to post collateral if necessary	• Ability to fill capacity requirements • Portfolio fit: impact the offer has on (i) the demand and supply effect on CAISO zone and (ii) the ability of SCE's portfolio to meet SCE's RAR[128] • Project viability: ensure project can be constructed consistent with terms of RFO • Physical concentration risk[129] • Financial concentration risk

Sources:

[1] PacifiCorp 2009 RFP Flexible Resources, September 2005, pp. 26-38.

[2] PacifiCorp 2012 RFP Base Load Resources, April 5, 2007, pp. 30-35.

[3] Oklahoma Gas & Electric Company, RFP for Capacity and Energy Resources Years 2008-2010, Issued March 29, 2007, pp. 13-17.

[4] Arizona Public Service Commission 2007 RFP for Renewable Resources, March 5, 2007, pp. 8-11.

[5] Puget Sound Energy, RFP for All Generation Resources, January 2008, Exhibit B; and Puget Sound Energy, 2006 RFP for Long-Term Supply Side Resources, p. F-4.

[6] Progress Energy Petition for Determination of Need of Hines 4 Combined Cycle Unit, August 4, 2004, pp. 50-66.

[7] Northwestern Energy RFP issued July 2, 2004, pp. 6-8.

[8] Entergy Fall 2006 RFP for Limited-Term Supply-Side Resources, October 24, 2006, Appendix E.

[9] Georgia Power Company and Savannah Electric and Power Company 2009 RFP, July 5, 2005, pp. 18-19.

[10] Southern California Edison 2006 New Gen RFO, Transmittal Letter, August 14, 2006, pp. 15-16.

127 Potentially including capacity payments, start up charges, variable operating and maintenance costs, and fuel costs resulting from offer heat rates.

128 Factors influencing the portfolio fit could also include but are not restricted to: the range of offers that are available for selection; variable costs; volume in MW offered; unit flexibility (e.g., ramp rates, start times, ancillary service capabilities); the proposed initial delivery date; and the agreement's duration.

129 Portfolio Concentration Risk referred to both (1) "portfolio concentration risk" reflecting potential electric system reliability and continuity of service risks from over reliance on purchases from a particular technology, and (2) "financial concentration risk" from significant monetary exposure to a single counterparty. CPUC Decision 02-10-062 requires SCE to devise procurement strategies that procuring generation from a variety of fuel sources and a variety of counterparties.

APPENDIX E – STATES WITH PROCUREMENTS FOR RETAIL SUPPLY OF FULL REQUIREMENTS SERVICE

Overall Frameworks Used in Selected States Procuring FRS Supply[130]

	CT	DE	DC	ME	MD	MA	NJ
Does state have regulations about FRS procurement?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Bid Payment Form	Pay-as-bid	Pay-as-bid	Pay-as-bid	Pay-as-bid	Pay-as-bid	Pay-as-bid	Uniform price
Price-only offers?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Are generation-owning affiliates able to bid?	–	Yes	Yes	Yes	Yes	Yes	Yes (With BPU approval)
Annual "lessons learned" process?	Yes	Yes	Yes	–	Yes	No	Yes
Does bidder eligibility include credit criteria?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Do bidders need to post collateral?	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Do bidders provide indicative bids?	No (based on recent RFP)	No (based on recent RFP)	No	Yes	No (based on recent RFP)	Yes	Yes
Who oversees process on a daily basis?	Utility, with oversight by IM	PUC, with help of PUC-retained IM	IM	PUC; No IM	IM (retained by utilities)	Utility No IM.	IM retained by utilities; BPU has a consultant
Time between submitting final bids and selection of winner	5 hours (e.g., UI's recent SOS procure-ment)	1 day	1 day	1+ months	4 hours beginning in 2008 (previously 1 day)	5 hours (e.g., recent RFP)	~50 minutes between bidding rounds
Timing of RFPs / Auction	Separate RFPs for each utility (one solicits semi-annually; the other each year)	Largest utility staggers two tranches (1-2 months apart)	Only one utility	All utilities procure power at same time but use separate RFPs.	All utilities procure power at same time but use separate RFPs.	Utilities stagger annual procure-ments (2 in Jan, 1 in Feb, 1 in Mar)	All utilities solicit through a single auction

130 There are other states (e.g., Illinois) that have carried out FRS procurements.

Additional information About Products Recently Procured in Selected States Procuring FRS Supply[131]

State	FRS Products Procured:
CT	Four product classes for standard offer service with separate pricing for: (1) residential; (2) small commercial and industrial; (3) large commercial and industrial, and (4) street lighting classes. Both major utilities have used a laddering approach, with a portion of the total power requirements contracted over a three-year cycle, to create a blended portfolio.
DE	Four product classes, in two overall groupings: Small – residential/small commercial and industrial: procurement has 3 contract lengths, offered simultaneously (13-month term, 25-month term, and 37-month term in 2005; in 2006 only a 36-month term); Larger – (a) medium general service – secondary; (b) large general service – secondary; and (c) general service – primary customers: 13-month term only in 2005 (in 2006 only a 12-month term)
DC	Three product classes, procured via the following two contract terms: (1) residential and (2) small commercial = 30% using 16-month contracts; 30% using 28-month contracts; 40% using 40-months or more; (3) large commercial 60% using 16-month contracts; 40% using 28-month contracts;
ME	Three product classes: (1) residential/small commercial: procurement is 3-year contract offered once per year for 1/3 of load; (2) medium commercial/industrial and (3) large commercial industrial: procurement is 6-month contract offered twice per year for 100% of load
MD	Beginning in 2008 the products are: (1) residential and small commercial: 2-year contracts for 25% of load, RFP issued twice a year; and (2) mid-to-large commercial and mid-sized industrial: 3-month contracts for 100% of load, RFP is issued 4 times a year
MA	Two product classes: (1) residential (and small commercial): procurement is 12-month contract offered twice per year for 50% of load; and (2) medium/large commercial & industrial: procurement is 3 month contract offered 4 times per year for 100% of load.
NJ	Two types of contract approaches: (1) fixed price contract to serve small to mid-size customers; must serve a fixed % share of load; 3-year contract; 1/3 of load procured each year (2) hourly-priced contract for large customers; must serve a fixed % share of load; receive a capacity payment and an energy payment determined by the PJM real-time hourly market; 1-year contract; 100% of load procured

[131] There are other states (e.g., Illinois) that have carried out FRS procurements.

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As part of our analysis of competitive procurements of retail electricity supply, we compiled and reviewed a substantial amount of literature. These documents include regulations, opinions, and reports from government agencies; white papers from industry experts and interest groups; actual procurement documents; and other sources in the public domain.

These documents are posted on the website of the NARUC-FERC Collaborative Process on Competitive Procurements. Members of the public can gain access to these documents by logging on to the website as a guest. The address is:

http://procurement.webexworkspace.com/login.asp?loc=&link=

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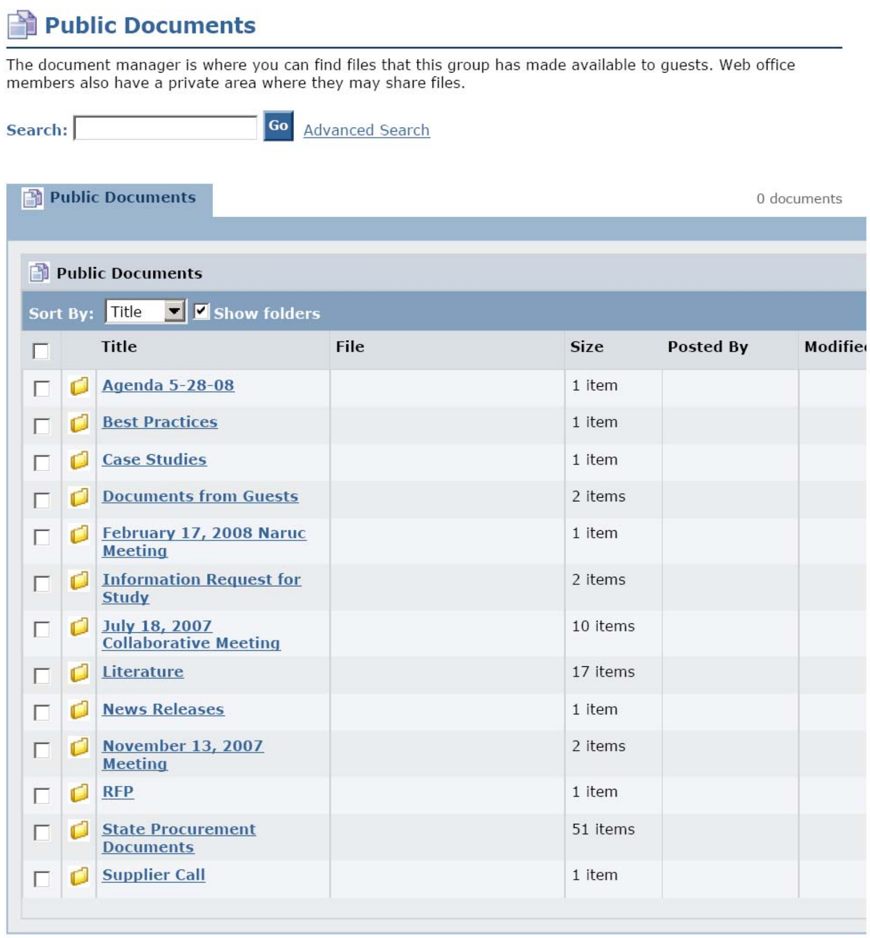

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Information Request for Study		2 items		
July 18, 2007 Collaborative Meeting		10 items		
Literature		17 items		
News Releases		1 item		
November 13, 2007 Meeting		2 items		
RFP		1 item		
State Procurement Documents		51 items		
Supplier Call		1 item		

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UM 1182

In the Matter of
NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION

Petition for an Investigation Regarding Competitive Bidding

Phase 1 Reply Comments of the Northwest and Intermountain Power Producers Coalition
April 22, 2011

Attachment 2

NIPPC's Proposed Revision to the RFP Guidelines

5. Independent Evaluator (IE): *An IE must be used in each RFP to help ensure that all offers are treated fairly. Commission Staff, with input from the utility and interested, non-bidding parties, will recommend an IE to the Commission, which will then select or approve an IE for the RFP. The IE must be independent of the utility and likely, potential bidders, and also be experienced and competent to perform all IE functions identified in these Guidelines. The IE will contract with and be paid by the utility. The IE should confer with Commission staff as needed, on the IE's duties under these Guidelines. The utility may request recovery of its payments to the IE up to completion of the Report on the Shortlist Selections in customer rates, but the utility may not pass on the costs of IE services during the final negotiations to customers in rates.~~.~~ If retained through final negotiations, the final winning resource(s) will be responsible for compensating the utility for payment for the IE's services during final negotiations. If more than one resource is selected, the resources will allocate the costs proportionally to the estimated lifetime revenue of their projects. If the utility's ownership option is the winning resource, the utility's shareholders would pay the IE costs for final negotiations just as any other winning independent bidder.*

10. Utility and IE Roles in the RFP Process:

a. The utility will conduct the RFP process, score the bids, select the initial and final short-lists, and undertake negotiations with bidders.

b. The IE will oversee the RFP process to ensure that it is conducted fairly and properly.

c. If the RFP does not allow affiliate bidding and does not include ownership options (i.e., the utility is not including a Benchmark Resource or considering ownership transfers), the IE will check whether the utility's scoring of the bids and selection of the short-lists are reasonable.

d. If the RFP allows affiliate bidding or includes ownership options, the IE will independently score the utility's Benchmark Resource (if any) and all or a sample of the bids to determine whether the selections for the initial and final short-lists are reasonable. In addition, the IE will evaluate the unique risks and advantages associated with the Benchmark Resource (if used), including the regulatory treatment of costs or benefits related to actual construction cost and plant operation differing from what was projected for the RFP.

e. Once the competing bids and Benchmark Resource (if used) have been scored and evaluated by the utility and the IE, the two should compare results. The utility and IE should attempt to reconcile and resolve any scoring differences. If the two are unable to agree, the IE should explain the differences in its ~~Closing~~ Report on the Shortlist Selection.

f. The utility must retain the IE through the final negotiations in any RFP including a utility ownership option among the final short list. That would include any RFP with a benchmark resource or with a build-to-own transfer option still among the potential winning resources at the short list selection stage. The IE may be retained through final negotiations in RFPs without a utility ownership option, if the circumstances warrant retention of the IE, as deemed necessary by the Commission on a case-by-case basis. If the IE is retained through final negotiations, the IE's role is to act as an independent monitor during the final negotiations who will observe and *document the tenor, topics and fairness of the final bidding negotiations amongst final bidders with contrast to the utility's treatment of its bid-in benchmark resource or other utility-ownership option. The IE shall monitor contact among the Company and bidders to ensure all parties communicate effectively and that all disputes are resolved quickly.*

11. IE ~~Closing~~ Reports: *The IE will prepare a ~~Closing~~ Report on the Shortlist Selection for the Commission after the utility has selected the final short-list. In addition, the IE will make any detailed bid scoring and evaluation results available to the utility, Commission staff, and non-bidding parties in the RFP docket, subject to the terms of a protective order. The IE will prepare a Report on the Final Negotiations for the Commission after the utility has completed the RFP.*

12. Confidential Treatment of Bid and Score Information and any other trade secret information contained in the IE Reports: *Bidding information, including the utility's cost support for any Benchmark Resource, as well as detailed bid scoring and evaluation results, as well as any information in the IE Reports protected as trade secrets under Oregon law or Commission regulations, will be made available to the utility, Commission staff and non-bidding parties under protective orders that limit use of the information to RFP approval and acknowledgment, and will also be made available under protective orders to parties in subsequent to cost recovery proceedings.*

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 22nd day of April, 2011, a true and correct copy of the within and foregoing **NORTHWEST AND INTERMOUNTAIN POWER PRODUCERS COALITION'S REPLY COMMENTS** was served as shown to:

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Signed________________
Gregory Adams

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Attachment 1

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