PUC-IR-31 **(All Parties except KIUC)**

Ref: HREA-KIUC-IR-1.

a. Should the competitive bidding process be different for an IOU than for a co-op?

b. Please comment on KIUC's contentions that competitive bidding should be used by it only when KIUC initiates the process and has sole authority for key project decisions.

c. Please comment on KIUC's contentions that its Board of Directors "provides the same oversight and risk mitigation for its members as would an ICA [independent contracting agent] for ratepayers of an investor-owned utility."

<u>HECO Response:</u>

a. Each IOU and co-op should be able to structure the competitive bidding process to meet their individual circumstances and requirements within the established guidelines. The details of the evaluation process, evaluation criteria, contract provisions, economic models, input assumptions, process and schedule should all be at the discretion of the individual utility. For example, even in states with prescribed bidding guidelines or rules, the structure of the RFP and the solicitation process can differ significantly from one utility to the next.

b. HECO generally agrees with KIUC regarding the role of the utility in the competitive bidding process

c. HECO strongly objects to the role of the ICA. Furthermore, there is no guarantee that the ICA can provide a more effective oversight and risk mitigation role for the utility customers than the utility itself. This assumes that the ICA has more knowledge and expertise than the utility in evaluating resource options and selecting those options that provide the best value for its customers, a contention HECO strongly refutes. HECO is not able to comment on the specific role of the Board of Directors of KIUC. Certainly, however, the Board of Directors of KIUC would have a fiduciary responsibility to its customers, while the ICA would have no such responsibility.

PUC-IR-32 **(HECO)**

HECO SOP, Exhibit A at 34 states:

> As noted in the response to Issue 2, the HECO Companies recommend that the IRP be used to identify the timing and amount of resource requirements along with the preferred resource or resources. The RFP will then be used to fill that need based on actual market options.

And HECO SOP, Exhibit A at 35 states:

> HECO supports a multi-stage evaluation system that includes threshold, price and non-price evaluation criteria. <u>HECO, however, proposes to use a price-driven process as the basis for selection of the preferred resources</u>. (Under such approach, the utility subjects all proposals to the threshold criteria, then organizes or clusters bids that pass the threshold criteria by type of resource (i.e. wind bids, combined cycles and combustion turbines will be evaluated together) and subjects all proposals to a price screen and non-price analysis. Price and non-price points are determined for each proposal within the cluster. <u>The best projects within each cluster (from a price and non-price perspective) are included on the short list.</u> Generally, all proposals on the short list are considered viable and feasible projects. <u>The final evaluation is based on determining the option or portfolio of options which result in the lowest net present value revenue requirements for the overall resource plan</u>.) *(emphasis added)*

And HECO SOP, Exhibit A at 39 states:

> Based on the detailed or portfolio analysis, <u>the preferred resources can be selected based on their total system cost impact</u>. *(emphasis added)*

And HECO SOP, Exhibit A at 44 states:

> HECO proposes a process whereby the IRP is initiated first before the RFP is issued. The IRP identifies the preferred resource plan. The IRP also determines the amount and timing of resources required, the preferred capacity type, any preference or criteria for resource selection, and determines the avoided cost. The preferred plan or target portfolio is identified.
>
> In parallel with this process, the utility develops the RFP. The RFP is issued after the preferred plan or target portfolio is identified. The utility then collects and evaluates bids from suppliers. The bids are compared to the cost of the generic resource or project selected in the IRP. The preferred bid is selected from the bids received and evaluated and the utility negotiates a contract with the selected bidder.

Is there any contradiction or tension between the proposed RFP selection procedure, which is based on minimizing net present value revenue requirements, and the approach underlying the IRP process, which takes into account many factors other than cost? Please elaborate.

<u>HECO Response:</u>

There is a potential for tension between the resource selection procedure in an RFP process, and the selection of a preferred plan in an IRP process. There are procedures that can be used to mitigate, but probably not eliminate, the potential tension. That is one important factor to consider in determining whether a competitive bidding process should be used for all resources, or perhaps for selected resources. HECO has indicated that both price and non-price factors will be considered in the evaluation of bids, similar to the IRP process. Presumably, as in most competitive bidding processes, the bids selected for the short-list will attain high price and non-price scores and be considered viable options from a non-price perspective. Also, HECO has proposed to quantify as many costs as possible in the quantitative analysis, including transmission-related costs associated with each project, system operation cost impacts, environmental costs, flexibility options, and equity adjustment impacts.

In the competitive bidding process, non-price criteria are generally balanced with price criteria to evaluate and select bids for a short-list or even final selection. There is a challenge to combine non-price points with a pricing relationship between proposals. The conversion of price scores to points is an issue that emerges in some bidding processes. As a result, many solicitations use the combination of price and non-price scores to select a short-list and then determine their portfolio based on price only. The non-price criteria used in the evaluation process can be quite inclusive. Non-price criteria are generally defined in the following categories:

(1) Project development feasibility (siting status, ability to finance, environmental permitting status, commercial operation date certainty, engineering design, fuel supply status, bidder experience, and reliability of the technology);

(2) Project operational viability (operation and maintenance plan, financial strength, environmental compliance, and environmental impact);

(3) Operating profile (dispatching/scheduling, coordination of maintenance, operating profile such as ramp rates, quick start capability, etc.);

(4) Flexibility (in-service date flexibility, expansion capability, contract term, stability of the price proposal).

While selection of the winning bid or portfolio of resources is generally based on total net present value revenue requirements, some utilities will use least cost as an indicator of selection but will use non-price factors as a "tie breaker". For example, through the process identified above, at the end of the process it will be possible to compare different projects or portfolios relative to their non-price scores and total net present value revenue requirements.

PUC-IR-33 **(HECO and CA)**

Ref: HECO SOP at 12-13; HECO Exhibit A at 18; CA SOP at 45-49.

Please explain how the Company's preferred approach to how competitive bidding could be integrated within the current IRP framework is different from that proposed by the CA.

<u>HECO Response:</u>

HECO and CA's preferred approach with regard to the integration of competitive bidding with the IRP framework are generally consistent. There are a few differences in each proposal. First, HECO does not support the CA's position that the resource identified as the preferred resource in the IRP would necessarily serve as the utility's contingency plan should the competitive bidding process not be successful. HECO prefers to maintain the option for submitting a bid in response to the RFP and utilizing the time between the submission of the IRP and the date bids are due to refine the characteristics and pricing of its own resource option. Also, HECO's preferred contingency plan may be different depending on the timing of IPP project failure. If an IPP project fails close to the time it is scheduled to go into service, HECO's only reasonable option may be to install emergency generators rather than its own project.

Second, HECO's preferred position is that the Commission should approve the RFP before it is issued, while the CA is non-commital on this issue (see page 49 of the CA's SOP).

Third, HECO does not believe that the role of the Commission to resolve disputes between the utility and bidders or among bidders, as suggested by the CA, is an efficient or effective role for the Commission. Direct Commission involvement as a referee in the operations of the competitive bidding process will encourage bidders and others to frequently contact the Commission to favor their own cause and may jeopardize the fairness and objectivity of the competitive bidding process. For example, if a Commission staffer provides information to one bidder but not to another the integrity of the process can be compromised. HECO's recommended approach for conducting informational meetings with the Commission throughout the process could meet these objectives of the CA without placing the Commission in a direct day-to-day role in the process. HECO understands that in other processes where the Commission had a direct active role, it proved to be an invitation for bidders to contact the Commission to vent their concerns and attempt to achieve a more favorable result.

PUC-IR-34 **(HECO)**

Ref: HECO SOP at 13 states:

> [t]he utility also would have the right to submit proposals for resources that may differ from the preferred resource type included in the preliminary resource plan."

Please describe under what circumstances the utility might propose a resource different from that which it identified in its resource plan.

HECO Response:

There is likely to be a reasonable time lag between the completion/submission of the IRP, review and approval of the IRP, development and issuance of the RFP, and receipt of bids. During that process, market conditions or technological advancements could change. HECO would, therefore, prefer to incorporate any changes in market conditions in its proposal similar to other bidders to ensure it includes the most up-to-date information available to provide the lowest reasonable cost option for the customers. As an example, Portland General Electric initially proposed F class technology for its preferred unit as an option for its 2003 RFP. However, the company conducted additional research, received pricing quotes from equipment vendors and eventually selected G class technology. This technology was slightly higher cost from a capital cost perspective but was more efficient with a better heat rate. In light of rising natural gas prices, the Company preferred a technology that was more fuel efficient.

PUC-IR-35 **(HECO)**

Ref: HECO SOP at 13.

HECO states that the "IRP Plan would establish the parameters for the RFP."

a. Please explain further what "parameters" would be established.

b. If the IRP Plan would establish these parameters, does this imply that the Advisory Group would have an opportunity to provide input on the parameters?

HECO Response:

a. HECO identified two options for integrating competitive bidding into the IRP process. (See HECO SOP, Exhibit A, pages 17 - 20.) The parameters referenced in this IR pertain to option 1 where the IRP process is first conducted to identify a preliminary preferred resource plan and the competitive bidding process is then conducted such that the resources in the final integrated resource plans are selected from the bids. The parameters established by the preliminary preferred plan would include capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes.

b. Yes, the IRP Advisory Group would have an opportunity to provide input on the parameters.

PUC-IR-37 **(All Parties except CA)**

Ref: e.g., CA SOP at 51-54.

Can a competitive bidding program succeed in the absence of the changes proposed by the CA to the IRP Process?

<u>HECO Response:</u>

The HECO Companies note that the comments and proposals in the CA SOP at pages 51-54 relate more to concerns by the CA over the IRP process in general, as it presently exists, as opposed to IRP process changes that are crucial to the effective integration of a competitive bidding process with the IRP. Specifically, these generalized IRP process concerns result in the following three primary recommendations by the CA for change to the IRP process:

> First, the Commission must make clear that utilities are required to provide stakeholders with detailed information regarding their needs at the outset of the "public participation" phase of the IRP review. CA SOP at 51.
>
> The Consumer Advocate also recommends amendments to the IRP rules to improve the overall timing of resource planning review cycles. CA SOP at 52.
>
> Finally, the Consumer Advocate recommends that the IRP Rules be amended to make explicit [that] the process by which utilities gain preapproval of capital improvements in excess of $2,500,000 should be amended to place upon an applicant the legal burden to demonstrate that a proposed electric generation project is consistent with its most recently approved IRP annual update. CA SOP at 54.

The HECO Companies do not believe that the success or failure of a competitive bidding process hinges on any of these changes to the IRP process proposed by the CA. While the Companies believe that a competitive bidding process (if implemented in Hawaii) and the IRP process should be integrated, the Companies position is that the IRP Plan can continue to be developed using the current process followed by the HECO Companies. In this case, the role of the IRP Plan should be to identify the preliminary "preferred" resource plan, define capacity and energy requirements, the timing of need, any preferred technologies, and potentially any other preferred attributes. The IRP Plan can also be used to identify any preferences or criteria for resource selection and can be used to determine avoided costs. In this model, the role of the RFP would include the solicitation and evaluation of resource options to meet the capacity and energy needs identified in the preliminary preferred resource plan. The RFP can be used to solicit bids for either a block of resources as defined in the IRP Plan or for the next required resource identified in the IRP Plan. The utility would essentially complete its preferred resource plan after the bids are received – final bid(s) selected would be part of the final IRP Plan. HECO SOP at 12 - 13.

Finally, should competitive bidding be implemented in Hawaii, revisions to the IRP Framework may be appropriate to account for the integration of the RFP and IRP processes. It would be premature to propose specific changes to the Framework before competitive bidding guidelines, if any, are adopted. HECO SOP Exhibit A at 44.

PUC-IR-39 **(All Parties)**

a. Should the competitive bidding process be an "open" bidding process, wherein the utility or the commission develops self-scoring criteria and bidders know what the utility is seeking and how the bid will be evaluated?

b. Or should it be a "closed" bidding process, wherein the utility provides general guidance about planning objectives, but does not reveal all of the information about the evaluation process?

HECO Response:

a. HECO supports the position that a competitive bidding process should not be an open bidding process. The early competitive bidding processes were largely open, self-scoring processes. As HECO has noted (see pages 1- 3 of Exhibit B of HECO's SOP), self-scoring processes encouraged gaming since bidders would attempt to present information in their bids designed to maximize their point totals only. As a result, these processes led to significant litigation since bidders knew their own scores and could guess the scores of their competitors. If bidders felt the scoring was in error, they would complain to the Commission. Furthermore, the price evaluation methodologies were simplistic, usually a spreadsheet which compared the net present value of the bid price against the net present value of the utility's projected avoided cost. Utilities were not able to optimize their portfolio because such simple models did not allow for project dispatching or reflection of other operating parameters associated with each proposal. Also, many of the projects accepted through these early self-scoring processes failed. Self-scoring systems are seldom (if at all) now implemented.

b. A closed bidding process is more typical of current systems. Under a closed bidding system, the utility usually provides a reasonable amount of information about the evaluation process and the methodologies to be used to evaluate bids, the criteria of importance to the utility, in some cases, the indices allowable to bidders for incorporation into their pricing formulae, and the basis for selecting a short-list and final award group. The RFP requests information from bidders that is used in the evaluation. Under a closed system, the bidder does not have access to the utility's bid evaluation models or the detailed non-price criteria used to evaluate individual bids. Bidders, therefore, have to focus on developing the details of their own project consistent with the information requested by the utility to ensure the bid is competitive and reasonably mature rather than attempt to maximize the points they would achieve in an open system. In HECO's view, a closed system is more equitable and fair to bidders since gaming is not possible and such a process allows for a more detailed and comprehensive evaluation of all bids. The models used are more sophisticated and allow for a detailed assessment of the system impacts of all bids, thus capturing the true costs to customers.

PUC-IR-40 **(All Parties)**

Ref: CA-HECO-IR-7.

a. Should competitive bidding be required for all transactions, required but subject to exceptions, or merely encouraged but not required?

b. If there are to be exceptions to a competitive bidding requirement, what should those exceptions be based on?

<u>HECO Response:</u>

a. HECO supports the option that competitive bidding should be encouraged but not required. HECO recognizes the CA's position that competitive bidding should be the default approach to securing new resources unless the utility or other affected party can demonstrate that competitive bidding would not be practical and can demonstrate that competitive bidding would be contrary to the public interest.

b. HECO suggests that the competitive bidding process should not be required for defined capacity needs of 25 MW or less. Also, resource requirements that cannot conform to the time required to implement a solicitation process should be exempt. Finally, any expansion or repowering of existing company units should be exempt. As an example, the recently developed Market-Based Mechanism to Evaluate Proposals to Construct or Acquire Generating Capacity to Meet Native Load in Louisiana identified several exceptions to the competitive bidding process, including resources less than 35 MW, modifications to an existing unit which expands the unit by 50 MW or less, and projects with a low installed cost.

PUC-IR-41 **(All Parties)**

Ref: HECO-HREA-IR-6.

a. Should there be a "dollar threshold above which competitive bids would be required"?

b. How should this dollar threshold be determined, and how often should it be reevaluated?

HECO Response:

a. HECO has concerns about requiring projects over a given dollar threshold to be competitively bid. For example, the implementation of competitive bidding cannot be allowed to negatively impact the reliability of the electric utility system. HECO SOP at 2. Also, as-available renewable energy generation has different characteristics than firm capacity, and the timing of when such resources are added to the utility's system is not nearly as important to the reliability of the system. It may be appropriate to establish a separate competitive procurement process to acquire as-available renewable energy generation, particularly given state energy policy that favors the development of renewable energy generation. HECO SOP at 3. These types of considerations should not be forgotten, in favor of bid/no-bid decisions based on dollar thresholds alone.

b. Not applicable.

PUC-IR-42 **(All Parties)**

Ref: CA-HECO-IR-7.

Should "near-term" needs be exempted from the competitive bidding process? If so, how should "near-term" be defined?

HECO Response:

Please note that HECO cannot find any use of the description "near-term" in its response to CA-HECO-IR-7. HECO is, therefore, uncertain if the "near-term" description is the PUC's paraphrase, an incorrect quotation, or if the wrong IR was cited.

Notwithstanding this uncertainty, HECO does take the position that it would be imprudent to apply a new competitive bidding process to new generation that must be added sooner than generation could be added using the process that has yet to be developed.

Further, because of the length of time needed to develop and implement a well-designed competitive bidding process, certain utility capacity addition projects already under development should not be subject to the competitive bidding process. These projects (i.e., HECO's Campbell Industrial Park Unit 1, MECO's Maalaea unit M18, MECO's Waena Unit 1, and HELCO's Keahole Unit ST-7) are described in the SOP, Exhibit A, page 9, and the response to CA-HECO-IR-13.

PUC-IR-43 **(HECO)**

HECO SOP, Exhibit A at 27 states:

> Given the time that it takes to develop and implement competitive bidding processes, it will be necessary to exempt certain near-term facilities from these processes to future units to allow for near-term needs to be met in a timely manner.

a. Please specify the near-term facilities that HECO believes must be exempted from any RFP process.

b. Once these near-term facilities are built or acquired, when does HECO next expect to need substantial new supply-side resources?

c. Please estimate the in-service date and magnitude of the first resources likely to be acquired under a competitive bidding process, in the event that this approach is used.

HECO Response:

a. As described in the response to PUC-IR-42, HECO believes that HECO's Campbell Industrial Park Unit 1, MECO's Maalaea unit M18, MECO's Waena Unit 1, and HELCO's Keahole Unit ST-7 should not be subject to competitive bidding.

b. The need dates for substantial firm capacity, following the installation of the units cited above, are currently being evaluated in each company's IRP-3 process. The need dates can be influenced by various assumptions, including load growth, energy efficiency DSM, load management DSM, Combined Heat and Power, Equivalent Forced Outage Rates, planned outage schedules, etc.

   - HECO's IRP-3 is currently in progress and the need date for the next increment of generation following Campbell Industrial Park Unit 1 will be determined using updated assumptions. The need date for a second increment of firm central-station generating capacity is dependent upon several factors, including but not limited to, the forecasted peak demand, the forecasted peak reduction benefits from energy efficiency and load management DSM, the forecast for DG/CHP on the system. In the IRP-3 integration analyses, six resource plan concepts were developed with Advisory Group input. For each resource plan concept, a representative long-term resource plan with specific resource selections and timing were developed. These were called finalist plans. Each finalist plan was evaluated under a number of scenarios. (Please refer to HECO's responses to CA-IR-280 and -282 in Docket No. 04-0113 [HECO Test Year 2005 rate case] for additional information about the finalist plans.) Under the base scenario, the second increment of firm capacity could be needed as soon as 2015 in the "Meets the State RPS Law – Oahu Only Plan." In other finalist plans, the next increment of firm capacity could be needed as late as 2022. In a scenario in which there is a moderate amount of DSM and CHP penetration, the next increment of firm capacity could be needed as soon as 2013. The scenario analysis was presented to the IRP Advisory Group on November 15, 2004.

As another point of reference, when the HECO IRP-2 Evaluation was filed in 2004, this need date was estimated to be 2015.

- HELCO's IRP-3 is currently in progress and the need date for the next increment of generation following Keahole ST-7 will be determined using updated assumptions. As a point of reference, when the HELCO IRP-2 Evaluation was filed in 2004, this need date was estimated to be 2017.
- MECO's IRP-3 is currently in progress and the need date for the next increment of generation following Waena Unit 1 will be determined using updated assumptions. As a point of reference, when the MECO IRP-2 Evaluation was filed in 2004, this

need date was estimated to be 2012.

c. With the information currently available, HECO is uncertain (1) whether competitive bidding should be implemented, (2) what form of competitive bidding, if any, to implement, and (3) when to apply the process. Notwithstanding this uncertainty, HECO estimates that it could take 8 to 12 months to complete this proceeding, 12 to 24 months to approve a new competitive bidding process, 4 to 8 months to initially implement the process, and seven years or more to obtain environmental review of, and permits and approvals for, and to acquire the equipment for and install, the new generation. HECO SOP at 2. Therefore, it is estimated that new firm generating capacity with in-service dates in the range of nine to eleven years from now (i.e., in 2014 to 2016) could be acquired under a competitive bidding process in the event that this approach is used. With respect to the magnitude of the resources, it will depend on the findings of the IRP processes for each respective system. For HECO, firm supply-side resources in the range of 16 MW municipal solid waste to 180 MW coal-fired units were examined in IRP-3. For HELCO, firm supply-side resources in the range of 1 MW diesel generators to 30 MW coal-fired units are being examined in IRP-3. For MECO, firm supply-side resources in the range of 1 MW diesel-engine generator to 50 MW single-train combined cycle units will be examined in IRP-3. Subsequent IRP cycles may examine other unit sizes.

PUC-IR-44 **(All Parties)**

Ref: CA-HECO-IR-9; HECO-HREA-IR-11.

Should the competitive bidding process differ depending on what type of resource is to be acquired (e.g., renewable resources, new technologies, and traditional resources; supply-side and demand-side resources, as-available v. firm capacity resources; and distributed resources)?

HECO Response:

The HECO Companies identified in their SOP at page 1, the key issues in this docket, which include among others, (1) whether Hawaii electric utilities should implement competitive bidding for new generation, (2) what competitive bidding process, if any, should be implemented, and (3) which resources should be subject to the competitive bidding process (since there are significant differences between central station firm capacity, distributed generation, and as-available renewable generation). The answers to these questions may not be the same for each type of resource. Moreover, the questions are not independent. (For example, competitive bidding using the wrong competitive bidding process should not be implemented.)

With regard to DSM resources, it is important to recognize that these resources are very different from supply-side resources and any bid process for new generation should not apply to DSM. In the past, in some cases the industry attempted to evaluate DSM and supply-side resources using the same evaluation criteria and RFP. However, these processes proved to be flawed because the resources are inherently different. The industry standard over the past bidding cycle (e.g., since the late 1990's) has been to conduct supply-side only solicitations, rather than all-source solicitations. DSM RFP's have not been common recently. HECO recommends that should competitive bidding be implemented in Hawaii, DSM options not be eligible to bid. SOP at pages 26 – 27.

Further, the competitive procurement process for distributed generation ("DG") may be different than the competitive procurement process for generation that provides power directly to the utility or sells power to the utility. For combined heat and power ("CHP") resources (a type of DG), it is important to recognize that these resources are very different from traditional supply-side resources providing power to the grid and should not be subject to the same bid process. The Companies plan to use a competitive procurement process for CHP resources installed at customer sites, as explained in the generic DG investigation, Docket No. 03-0371. The objectives of the competitive procurement process are, among others, (1) to ensure provision of quality CHP products and services, (2) to standardize equipment and designs, (3) to achieve efficiency in the equipment selection process, and (4) to obtain cost saving for the utility and its ratepayers, especially over the life cycle of the CHP installation.

Also, as-available renewable energy generation has different characteristics than firm capacity, and the timing of when such resources are added to the utility's system is not nearly as important to the reliability of the system. It may be appropriate to establish a separate competitive procurement process to acquire as-available renewable energy generation, particularly given the state energy policy that favors the development of renewable energy generation.

Another issue is the type and form of threshold criteria to apply for the competitive bidding process. The HECO Companies expect that more stringent threshold criteria (i.e., bidder has to demonstrate the technology used is mature, have site control, maintain certain credit ratings, etc.) will be necessary for the island systems since the risk of project failure can be significant for utility customers. Thus, for Hawaii utilities that do not have the option to acquire power from other jurisdictions, or even other islands, to backup potential unfulfilled project developer commitments, new technologies should not be eligible to bid in a supply-side RFP, or even if eligible to bid, are likely to be screened out by stringent threshold criteria.

While recognizing the distinctions noted above for the various types of resources that may be acquired, the overall process and procedures (i.e., evaluation and selection process, communication with bidders, general criteria, communications with bidders, etc.) for competitive solicitations can remain generally consistent across differing resource types. There will, however, be notable differences with regard to evaluation criteria of importance, the information requested of bidders which is tied to the evaluation criteria, specific contract terms, and possibly modeling methodologies.

As an example, Portland General Electric issued an RFP for supply-side options only. Eligible projects included IPP contracts, tolling arrangements, power plant purchase options, renewable resources, short-term firm contracts, and short-term options. Portland General included more than five different power contracts in the RFP package. It was also necessary to adjust some of the criteria for evaluating conventional supply-side resource and renewable resource options. The major difference was in the energy resource criteria. For example, to assess wind projects, the wind regime at the site is crucial. Likewise, for hydro projects, historic water flows is a crucial variable. The RFP contained specific criteria related to energy resources for each type of resource and tailored the questions requesting information from bidders around the specific requirements.

PUC-IR-45 **(All Parties)**

Concerning relations between developers and utilities, what are the most likely areas of dispute, and what Commission involvement (e.g., rules upfront, vs. dispute resolution later) is best suited to minimize these disputes?

HECO Response:

Competitive Bidding Process Issues

Developers of projects will want their projects selected in the competitive bidding process, and once their projects are selected, developers will want to maximize their returns on the projects on a risk adjusted basis.

As a result, developers of projects will want their projects considered more favorably in the screening and selection processes than the projects of other developers, or of the utility. If any criterion, or weight given to any criterion, will tend to result in the selection of one project over another project, the developers of projects that are favored by the criterion or the weight given the criterion will support the criterion or the weight given the criterion, and other developers may object to the criterion or the weight given to the criterion. If a developer of a project cannot develop its project within the timeframe required for new generation, then the developer of such a project may argue that the need for new generation must be later than that identified in the RFP.

Areas of dispute between developers and utilities with respect to the competitive bidding process may include, but are not limited to: (1) the basis of disqualification of a bidder due to failure to pass the minimum compliance or threshold criteria; (2) actual or perceived changes in the bidding process after submission of bids; (3) bidder claims that a utility has favored its own self-build option; and (4) disagreement over the pace of contract negotiations on both sides.

Should competitive bidding for certain forms of new generation be adopted in Hawaii, the HECO Companies are of the position that establishing the competitive bidding guidelines or rules up-front in the process is preferable to dispute resolution after the fact. It is more effective to take the time up-front to effectively develop the guidelines and procedures, which provide a clearer understanding of the process by all participants and a level of certainty at the outset to both the bidder and the utility. An attempt to resolve issues that breed disputes after the fact can lead to a contentious process every time the utility issues a solicitation, significantly driving up project costs (contrary to one of the primary objectives that competitive bidding is aimed to achieve) to the detriment of ratepayers. But of likely greater harm than increased costs is the potential for drawn out disputes to negatively impact the reliability of the isolated electric utility systems in Hawaii through delay in the final selection and ultimate implementation of needed firm capacity resources.

Power Purchase Agreement Issues

There may be disputes in the contract negotiation phase, because developers will want to maximize their returns on a risk adjusted basis, and the power purchase contract will affect their revenues, costs and risks. They generally also want to be able to finance their projects on a leveraged, project-financed basis (i.e., not secured by other assets or guarantees). Their project financing parties generally rely on cash flow and fixed cost coverage projections (and tend to discount revenue projections when prices vary with market factors, and input costs are not based directly on the same market factors). In simple terms, developers are most interested in power purchase contract provisions that affect revenues and revenue uncertainty (such as pricing provisions and curtailment provisions for as-available producers with low "fuel" costs), costs and cost uncertainty (such as interconnection requirements and performance standards) and risk allocation provisions (such as provisions that reduce payments based on availability or minimum availability, in-service delays, and failures to meet performance standards, and default and termination provisions). Developers generally want to be paid on a basis that tracks their own cost structure, and not the utility's cost structure upon which the utility's avoided costs are based. Developers tend to oppose flexibility provisions in power purchase agreements, because these provisions introduce another layer of analysis and complexity to financing parties.

To minimize disputes, provisions that can be standardized would be included in the "model" power purchase agreements(s) ("PPAs") attached to the RFP. See response to PUC-IR-73. For provisions that are resource specific, or where options may be proposed, bidders should be required to specify such provisions and options in their bids, so that the "value" of their proposals can be considered in the bid selection process. If the Commission supports the utility's efforts to hold bidders to their bids (if they attempt to change the deal in the PPA negotiation phase), disputes will be minimized.

PUC-IR-46 **(HECO)**

HECO SOP, Exhibit A, at 21 states:

> In fact, in several recent RFP processes, utility self-build or turnkey options have been the successful bidders among a large number of options, including recent Portland General Electric, PacifiCorp and Florida Power & Light RFP processes.

Do these examples include cases where the successful bidders were utility-owned generating affiliates or functionally separated generating divisions, as opposed to the utility *per se*? Please elaborate.

Response:

The three utilities mentioned are vertically integrated utilities. Although both Florida Power & Light and PacifiCorp have project development affiliates, the cases identified were self-build units proposed by the vertically integrated utility. In PacifiCorp's case, the utility selected two bids in response to its 2003-A RFP, a self-build option called Currant Creek and a turnkey option called the Lake Side Power Project.

PUC-IR-47 **(HECO)**

HECO SOP, Exhibit A, at 22 states:

> Portland General had to submit its proposal to the Commission in advance of receipt of other bids and had to provide the same information required of other bidders.

Is it common for the self-build option to be treated differently from other bids? Please specify.

HECO Response:

There is no consistent approach on the part of Commission rules or procedures for treating self-build options from other bidders. While there has been a recognition over the past few years that utility self-build options should be considered since they can represent competitive resource options, the approaches for considering such options have varied considerably. For example, in the Portland General Electric RFP process, the utility submitted a bid based on the same bidding requirements and information required of other bidders, and submitted the bid a day in advance of other bids. The Massachusetts bidding rules contained a requirement that utility bids had to be submitted to the Commission a day in advance of other bids. In other cases, utility bids may be submitted to an independent evaluator along with other bids. In the PacifiCorp 2003-A RFP, the utility developed a "Next Best Alternative" as a benchmark project. The project was evaluated along with all other projects and the independent evaluator reviewed the bid evaluation process. In some cases, utilities submit a cost only or cost with limited information about the project. In some cases, utility bids have not included the same level of non-price details as other bidders proposing Greenfield projects.

PUC-IR-48 **(HECO)**

HECO SOP, Exhibit A,at 22 states:

> The bidding rules in Quebec allow Hydro-Quebec Generation to bid into the Distribution Company's Call for Tenders process as long as everyone abides by the same rules. The Generation Company has been awarded contracts but other independent power producers have been successful bidders as well.

At Hydro-Québec, distribution and generation are functionally separated, with a code of conduct governing the relations between employees of the two divisions. In HECO's view, is this type of functional separation necessary in order for a utility's generation division to participate in an RFP without an unfair advantage?

HECO Response:

No. This type of separation is not a necessary condition for a utility generation option to compete in the utility's RFP. The functional separation of Hydro-Quebec was not a pre-condition for allowing the generation business unit to bid into the Distribution Company's Call for Tenders. There have been a number of cases where a vertically integrated utility has included a self-build option in the resource procurement process. Recent examples of vertically utilities which have offered self-build options include PacifiCorp, Portland General Electric, Florida Progress, and Florida Power & Light Company. There is no functional separation of generation and distribution in these cases. HECO is not aware of any cases where Commission bidding rules have required or encouraged functional separation in order for the generation division to participate in a host utility RFP.

PUC-IR-49 **(HECO)**

HECO SOP, Exhibit A at 42 states:

> There are a number of examples of recent RFPs that highlight these points. For example, the Portland General Electric RFP was developed within the bidding guidelines in Oregon. ... Portland General included general information about its self-build option in the RFP including the technology selected, estimated overnight capital costs, heat rate information, etc.

a. In the Oregon example cited, would the self-build option have been subject to cost-of-service regulation?

b. If not, on what basis would the cost borne by consumers of this new utility generation be established?

c. Is HECO aware of examples where the cost to consumers of a utility's self-build option is based on market factors?

HECO Response:

a. The PGE case in Oregon is a very complex case teetering on the fine line between revisions of regulations to affectuate industry restructuring and a return to consideration for cost based rates for utility built generation. The case has raised interesting issues related to approval of a self-build utility option in its resource plan, the utility request for a waiver of the application of OAR 860-038-0080(1)(b) so that the rule will not prohibit PGE from including the capital, operation and maintenance cost of the utility's Port Westward Project in its rates, and a determination by the Commission to require that the costs included in rates be based on the costs incurred or be subject to a market test.

While the Commission issued an Order in July 2004 (Order No. 04-376) granting PGE a waiver from OAR 860-038-0080(1)(b) for the Port Westward project, the ratemaking issues associated with new resources have not yet been decided. The above Order is attached as pages 6-10. (Order Nos. 05-133 and 04-375, which helps to give perspective to Order

No. 04-376, are attached as pages 3-5 and 11-23, respectively.)

b. As noted, the Commission has not yet made a decision on what basis the cost borne by customers for the new generation resource will be established.

c. HECO is not aware of any examples where the cost to consumers of a utility's self-build option is based on market factors. However, there have been a number of recent cases where a utility has acquired generation on the market and brought the projects into the rate base. It is our understanding that the costs of such options were based on the market. The article from Public Utilities Fortnightly entitled "Back to the Rate Base" by Michael Burr (March 2004) identifies a number of such projects which have been brought into rate base. (See attached pages 24-29 for a copy of the article.)

ORDER NO. 05-133

ENTERED 03/17/05

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1066

In the Matter of an Investigation Into Regulatory Policies Affecting New Resource Development.	)))	ORDER

DISPOSITION: DOCKET HELD IN ABEYANCE

In docket AR 417, the Public Utility Commission of Oregon (Commission) left one issue unresolved: whether to amend OAR 860-038-0080(1)(b) to require new generating resources to be included in the revenue requirement at cost, or maintain the current language of including new generating resources in the revenue requirement at market price, and not add the resource to an electric company's rate base. In October 2002, the Commission opened this investigation to resolve this issue by examining regulatory policy pertaining to new generating resources. The Commission staff (Staff) was directed to organize workshops to discuss:

1. How should new generating resources be treated for ratemaking?
2. In planning for new resources, which customers should the plan be designed to include?
3. In determining a resource acquisition policy, should competitive bidding occur, and, if so, to what extent?

See Order No. 02-872.

Since the docket was opened, Staff has held numerous workshops with the intervenors to discuss all aspects of the identified issues. In addition, the Commission held at least two workshops with the stakeholders. Subsequent to the last Commission workshop on December 16, 2003, intervenors and Staff filed several rounds of comments. On March 31, 2004, the Commission asked the intervenors and Staff to devise large customer opt-out proposals. Various parties filed comments to the Commission's request, with the final comments being received on June 2, 2004.

During this same time period, Portland General Electric Company (PGE) was undergoing a review of its 2002 Integrated Resource Plan (IRP) in docket LC 33. As part of its IRP, PGE recommended the construction of a self-owned gas fueled resource, known as Port Westward. Concurrent with its request for approval of its IRP, PGE asked the Commission to waive the application of OAR 860-038-0080(1)(b) as it would apply to Port Westward. Specifically, PGE asked that it not be prohibited from including: the capital costs incurred in building Port Westward in PGE's rate base; the operation and maintenance costs of Port Westward in its revenue requirement; and the costs of acknowledged contracts with third parties in its revenue requirement.

While we had only one docket, we wrote two separate orders. In Order No. 04-375, we acknowledged the IRP. In making our decision, we reviewed the competitive bidding process used by PGE. This review aided our determination that PGE's construction of a generic gas resource was an acceptable resource to include in the IRP. In Order No. 04-376, we partially granted the waiver request. While we waived the application of OAR 860-038-0080(1)(b) as to the Port Westward matters, we did not make any decisions about the inclusion of any Port Westward costs in rates. *Id.* at 4.

With this background, we turn to the issues raised in this docket. The comments submitted provide numerous valid reasons for including new generating resources in a utility's revenue requirement at cost, rather than at market price. We are still concerned, however, that the use of a cost standard will cause a utility to favor its own proposed resources. Two of our open dockets are intended to address the incentive and ability of a utility to favor its own projects. One docket, UM 1182, will revise the competitive bidding guidelines to ensure resources are considered on an equal basis. The other docket, UM 1056, will modify the least-cost planning requirements to foster a timely, efficient acquisition of new resources. Finally, we intend to open an additional investigation docket later this year to consider the use of performance-based ratemaking to offset utility bias in favor of owning its own resources. We want to wait until those proceedings are resolved to issue our final decision in this docket.

During the interim, the existing market price administrative rule remains in effect. If an electric utility wants to include a new resource in its revenue requirement at cost, as did PGE in docket LC 33, then the utility must file a request to waive the administrative rule.

We also expect parties to continue their efforts to craft an option for large customers to opt out of PGE's and PacifiCorp's new generating resources. By September 30, 2005, each company should file either an opt-out tariff for our review or a consensus report explaining that an opt-out is not workable.

Our decision may frustrate some parties. We recognize that one of the reasons activity in docket UM 1056 was suspended in late 2002 was to obtain resolution of the cost or market issue in this docket. To keep docket UM 1056 viable, we direct the parties to focus on cost, not market. We want the utility resource plans to identify resources that provide the best mix of low cost and risk.

ORDER

IT IS ORDERED that this matter is held in abeyance pending resolution of dockets UM 1056 and UM 1182, completion of an investigation into performance based ratemaking, and a determination of whether a large customer opt-out of new generating resources for PGE and PacifiCorp is possible.

Made, entered, and effective MAR 1 7 2005.

Lee Beyer
Chairman

John Savage
Commissioner

Ray Baum
Commissioner

PUBLIC UTILITY COMMISSION OF OREGON

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

ORDER NO. 04-376

ENTERED JUL 20 2004

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 33

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY	)	ORDER
	)	
	)	
OAR 860-038-0080, Resource Policies.	)	

DISPOSITION: OAR 860-038-0080(1)(b) WAIVER GRANTED, IN PART

In August 2002, Portland General Electric Company (PGE) filed its 2002 Integrated Resource Plan (IRP). On February 6, 2004, PGE filed an application for waiver of OAR 860-038-0080(1)(b) as that rule would apply to the acquisition of new generating resources described in the IRP. Specifically, PGE asked that the rule be waived so it would not prohibit PGE from including: 1) the Port Westward (Pt WW) capital costs in PGE's rate base; 2) the operation and maintenance costs of Pt WW in its revenue requirement; and 3) the costs of acknowledged contracts with third parties in PGE's revenue requirement.

The Northwest Independent Power Producers Coalition (NIPPC), Industrial Customers of Northwest Utilities (ICNU), Renewable Northwest Project (RNP) and Staff of the Public Utility Commission of Oregon (Staff) responded to PGE's application on March 8 and 9, 2004. PGE filed a reply to the responses on March 29, 2004.

The matter was held in abeyance pending resolution of a related docket, UM 1066.[1] In light of our order this date acknowledging PGE's IRP, and due to the complexity of outstanding issues in the UM 1066 docket (such as an opt-out plan for new resources), we determined to resolve PGE's motion in this separate order.

[1] Among other matters, we are considering whether OAR 860-038-0080(1)(b) should be amended in UM 1066.

Applicable Administrative Rules

OAR 860-038-0080(1)(b) states, in pertinent part:

> Electric companies must include new generating resources in revenue requirement at market prices, and not at cost, and such new generating resources will not be added to an electric company's rate base even if owned by the electric company;

OAR 860-038-0001(4) provides, in pertinent part:

> Upon application by an entity subject to these rules and for good cause shown, the Commission may relieve [the entity] of any obligations under these rules.

PGE's Request for Waiver

PGE claims that a waiver of OAR 860-038-0080(1)(b) will be in its customers' best interests. According to PGE, its Action Plan (Plan) establishes that the generating resource portfolio, which includes the Pt WW project, provides customers with the best combination of price and rate stability. Further, because the rule does not define "market prices," a waiver will remove the uncertainty of valuing contracts with third parties, and allow such contracts to be valued at cost.

PGE argues that OAR 860 038-0080(1)(b) should be waived because the environment for which the rules were originally drafted does not exist. Under the administrative rules, utilities would not acquire new generating resources except to serve residential and small non-residential consumers. The rules intended for larger consumers to be served by the market. In 2001, however, direct access was fundamentally changed by HB 3633, which required an electric utility to provide a cost of service rate option to all customers. Although some tweaking of the rules has occurred since HB 3633 was adopted, the premises under which the rules were developed have not been revisited. According to PGE, a waiver is now necessary to allow PGE to meet its cost of service requirements with a resource portfolio that provides stable costs and rates for customers.

Finally, PGE states that it will not build the Pt WW plant unless the Commission either waives the administrative rule, or modifies the rule through the related UM 1066 proceeding. Taking all of its arguments together, PGE argues it has established good cause for a rule waiver.

Participants' Positions

NIPPC, ICNU, RNP and Staff raise various objections, arguing that the application should be denied. NIPPC asserts that the Commission is being asked to make an important policy decision without the benefit of the UM 1066 discussions. Further, PGE has not demonstrated that waiver is in the best interests of its customers. Finally, for the Commission to acknowledge Pt WW and grant the waiver fails to advance the statutory directives of direct access.

ICNU argues that granting a waiver could harm the competitive market by increasing the vertical and horizontal market power of PGE. ICNU also claims that a waiver could result in new stranded costs, which would harm the development of a competitive retail market. Finally, ICNU is concerned that a viable opt-out option does not exist if the Commission should decide to approve the waiver.

RNP believes that the matter should be resolved in UM 1066, and not handled piecemeal in the LC 33 docket.

Staff raises both procedural and substantive objections to the application. First, Staff argues that determining the revenue requirement treatment of a generating resource is ratemaking, which is not lawful to do in an IRP docket. Second, PGE has failed to establish "good cause" for waiving the rule. Based on both reasons, Staff asserts that the Commission should deny the application.

PGE's Reply

PGE states that its application for a waiver is not unlawful, as it is not asking for a ratemaking decision regarding the inclusion of Pt WW costs and contracts with third parties in rates. Rather, PGE asserts it is solely asking the Commission to waive the rule in future ratemaking proceedings.

PGE also contends that it has established good cause as required by OAR 860-038-0001(4). The Plan PGE submitted on March 26, 2004, shows that the generating resource portfolio, which provides customers with the best combination of low cost and risk, includes Pt WW using "G" class technology at cost. With this showing, PGE argues that it has met the good cause requirement.

Commission Discussion

On this same date, we are issuing Order No. 04-375, which acknowledges PGE's Integrated Resource Final Action Plan (IRP). In that order, we do not address the issue of whether OAR 860-038-0080(1)(b) should be waived, or whether PGE's new generating resources should come into its revenue requirement at cost or market. Notwithstanding PGE's arguments about the legality of resolving such issues in an IRP docket, we believe that our IRP acknowledgement should be separate from our decisions about waiver.

Even though we have separated these matters into two different orders, we are clearly cognizant of the relationship between these orders, along with the relationship of this order to Docket UM 1066. It was our initial preference to issue an order in Docket UM 1066 simultaneously with the PGE IRP acknowledgment. However, UM 1066 is not yet ripe for an order, due in part to the lack of a viable opt-out option for industrial customers. Therefore, we decided to resolve the limited issue of PGE's waiver application by issuance of this order.

We address the Pt WW project first. Pt WW was presented in PGE's IRP as a self-built cost based resource. In reviewing the IRP, we examined various scenarios and variables surrounding Pt WW. Based on our review, we concluded that the construction or acquisition of 350 MWa of a high efficiency gas-fired resource should be acknowledged, which we did in Order No. 04-375. We further stated that, based upon our acknowledgement, PGE intended to build Pt WW using G-class turbine technology.

PGE asks us to waive the application of OAR 860-038-0080(1)(b) so that the rule will not prohibit PGE from including the capital, operation and maintenance costs of the Pt WW project in PGE's rates. It argues that when the Pt WW project was compared to third party bids submitted in response to PGE's Request for Proposal (RFP), PGE found the construction and operation of Pt WW would benefit customers as compared to other resource alternatives. The Pt WW project was scored and analyzed by PGE as a cost based, and not market priced, resource. There is no market price for Pt WW, and to review Pt WW at a market rate would take another RFP, according to PGE. Under the process done and analysis presented by PGE, we find that Pt WW at cost serves the interests of the customers.

We are charged with representing the customers of the public utilities. ORS 756.040. As we stated in Order No. 89-507 at 2:

> The goal of utility planning is to assure an adequate and reliable supply of energy at the least cost to the utility and its customers consistent with the long-run public interest.

We must also abide by the statutory electric restructuring requirements. In this instance, we grant the waiver as requested by PGE for the Pt WW project.

Our determination is not ratemaking. Prior to the passage of SB 1149 and the aforementioned rule, all costs that were prudently incurred were placed in a utility company's rates. We did not discuss, in prior IRP orders, whether we were engaged in ratemaking by acknowledging a utility company's resource action plan, as it was assumed that prudently incurred costs would be included in a company's rates. Our assumptions changed with the enactment of SB 1149, in that we now assumed that everything would be valued at "market." As discussed by several parties in this docket and in UM 1066, the phrase "market" has never been defined in the statute or rules. The valuation process applied to the resource, while vital to the ratemaking process, is not in and of itself, ratemaking.

Having said that, however, we do find ourselves teetering on a narrow line between acknowledging a resource, and making a ratemaking decision. We can say that the rule will be waived. However, we cannot make any decisions about whether to include the costs associated with Pt WW in rates, as those can only be made in a rate filing under ORS 757.205, *et seq.* In a future ratemaking docket regarding Pt WW, we will be looking carefully at PGE's assumptions and costs. We may also place a "cap" on PGE's costs by using the lowest comparable bid, or such other mechanism that PGE may bring to us.[2] Those decisions are, however, left for the future ratemaking proceedings.

[2] On June 22, 2004, PGE sent a letter to the LC 33 participants stating that PGE would hold workshops to develop mechanisms "for qualifying large customers to exempt themselves from costs and benefits of the Port Westward plant . . . and . . . to share with all its non-exempted customers the rewards and risk of potential PGE

PGE also requested a rule waiver for third party contracts. It appears to us that the cost and market price of those contracts is essentially the same. However, we will address the issue of contracts in the UM 1066 docket, so PGE's waiver request as to third party contracts is denied.

ORDER

IT IS ORDERED that:

1. Portland General Electric Company has shown good cause for waiver of OAR 860-038-0080(1)(b) as to the Port Westward project.

2. OAR 860-038-0080(1)(b) is not waived for the costs of any contracts with third parties.

3. PGE is to provide a status report regarding the discussions involving large customer opt-out and sharing construction cost risks and benefits within 90 days of the date this order is entered.

Made, entered, and effective ______________________________.

Lee Beyer Chairman	**John Savage** Commissioner
	Ray Baum Commissioner

A party may request rehearing or reconsideration of this order pursuant to ORS 756.561. A request for rehearing or reconsideration must be filed with the Commission within 60 days of the date of service of this order. The request must comply with the requirements in OAR 860-014-0095. A copy of any such request must also be served on each party to the proceeding as provided by OAR 860-013-0070(2). A party may appeal this order to a court pursuant to applicable law.

construction cost under-runs and over-runs." We welcome such discussion and ask that PGE report the status and content of those discussions within 90 days of the issuance of this order.

ORDER NO. 04-375

ENTERED JUL 20 2004

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

LC 33

In the Matter of	)	
	)	
PORTLAND GENERAL ELECTRIC COMPANY	)	ORDER
	)	
	)	
OAR 860-038-0080, Resource Policies.	)	

DISPOSITION: INTEGRATED RESOURCE FINAL ACTION PLAN ACKNOWLEDGED, WITH EXCEPTION AND CONDITIONS

We acknowledge the plan filed by Portland General Electric Company (PGE) on March 26, 2004, with one exception and three conditions. First, we acknowledge the construction or acquisition of a high efficiency gas-fired resource, rather than the specific Port Westward plant. We also reserve the issue of whether this gas-fired resource will be included in rates at cost or market. As for conditions, we require three: 1) PGE must discuss constraints on competitive renewable development in the region with Staff, renewable developers, Bonneville Power Administration (BPA), the Energy Trust of Oregon (ETO) and other stakeholders; 2) PGE must include an action item in its 2005 Integrated Resource Plan (IRP) to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional wind (and other) resources are accessible to PGE at a reasonable price; and 3) PGE must demonstrate that it has taken reasonable measures to acquire or option, as well as retain, cost effective transmission capacity over the Cascades before issuing its next Request For Proposal (RFP). Finally, we ask PGE to specifically address demand response program issues, outlined in the order below, in its next IRP.

Participants

Numerous entities have participated in this matter, including Northwest Independent Power Producers Coalition (NIPPC), Oregon Department of Energy (ODOE), Ascentergy Corporation, Citizens' Utility Board of Oregon (CUB), Energy Consulting Group, PGE, ETO, Renewable Northwest Project (RNP), Industrial Customers of Northwest Utilities (ICNU), Oregon Electric Utility Company, Northwest Energy Coalition (NWEC) and Utility Staff of the Public Utility Commission of Oregon (Staff).

Background

On August 9, 2002, PGE filed its 2002 IRP. PGE asked the Commission to: 1) acknowledge that the resource approaches and specific resource actions proposed in Chapter 8 of the IRP were in accordance with Order No. 89-507; and 2) find that the IRP meets the requirements of OAR 860-038-0080.

During a prehearing conference held September 13, 2002, the participants agreed that the only issue to be decided in this proceeding is whether PGE's 2002 IRP includes resource approaches and actions that are reasonable and consistent with the least cost planning policies and principles set forth in OPUC Order No. 89-507.

The participants held workshops, filed comments and responded to data requests. On December 23, 2002, Staff submitted a draft recommendation to the Commission, stating that PGE's IRP should not be acknowledged as filed because 1) the IRP lacked specificity; and 2) Staff disagreed with some of the IRP's cost assumptions.

Additional workshops were held. On March 4, 2003, PGE filed an IRP Supplement (Supplement). In the Supplement, PGE sought acknowledgement of only two action items: 1) its plan to issue an RFP in the summer of 2003; and 2) its plan to continue permitting and design work for its proposed self-built combined cycle combustion turbine (CCCT) at its Port Westward (Pt WW) site.

Participant comments regarding the Supplement were received on March 21 and March 24, 2003. On April 7, 2003, PGE filed a response to comments. On May 7, 2003, Staff's recommendations and PGE's response were presented to the Commission during a regular public meeting.

Based on arguments heard at the May 7, 2003 public meeting, additional written participant comments, and arguments heard at a June 9, 2003 public meeting, the Commission issued Order No. 03-461, approving PGE's plan to issue an RFP.[1] At the June 9, 2003 meeting, PGE withdrew its request for acknowledgement of its plan to proceed with siting and permitting of Pt WW.

After filing interim reports on the progress of the RFP process, PGE filed its Proposed Action Plan on January 14, 2004. Staff and other participants filed comments on the Proposed Action Plan to alert PGE to issues that the participants wanted addressed in PGE's Final Action Plan. On April 8, 2004, PGE filed a response outlining how participants' comments on the Proposed Action Plan were addressed in either the Final Action Plan or in responses to data requests.

[1] The RFP process was subject to the requirements of Commission Order No. 91-1383 and was monitored by Staff, an independent observer and other participants in Docket No. UM 1080.

On February 6, 2004, PGE filed an application for waiver of OAR 860-038-0080(1)(b), so that: 1) the rule would not prohibit PGE from rate-basing the Pt WW gas turbine project if it decided to pursue the project; 2) PGE would not be prohibited from including the operation and maintenance costs of Pt WW in its revenue requirement; and 3) PGE would not be prohibited from including the costs of acknowledged contracts in its revenue requirement. Participants responded to PGE's application on March 8 and 9, 2004. PGE filed its reply to the responses on March 29, 2004.

On March 26, 2004, PGE filed its Final Action Plan (Plan). On April 1, 2004, PGE described its filing to the Commission dring a public meeting. At the meeting, several participants made oral comments and raised questions about the Plan. Participants subsequently filed written comments about the Plan. On April 13, 2004, PGE provided a written response to questions raised by the participants.

On April 12, 2004, NIPPC filed a petition requesting the Commission to direct PGE to open a second phase of bidding to qualified bidders who participated in PGE's first RFP process. According to NIPPC, bidders should be directed to "beat" PGE's proposed configuration and costs for its proposed Pt WW plant. NIPPC believes that a second round of bidding would allow the Commission to assure itself that PGE's Plan offers PGE's customers the lowest cost resource.

On April 23, 2004, Staff filed its recommendations and draft proposed order regarding the Plan. On April 30, 2004, the participants filed comments. These comments were incorporated into Staff's final recommendation submitted May 19, 2004.

On May 26, 2004, a public meeting was held before the Commission. Staff presented its final recommendation, after which participants commented and raised issues to the Commission.

The Commission took the matter under advisement, and issues its determination in this order.

Overview of PGE's Final Action Plan:

PGE asks the Commission to acknowledge the following action items[2]:

1. Build one unit (350 MWa) of Port Westward (Pt WW) as a cost-based resource, using G-class turbine technology.
2. Acquire 25 MW of duct firing capability at Pt WW for peak loads and economic dispatch.
3. Acquire approximately 65 MWa (195 MW) of wind generation, provided that the necessary transmission and integration services can be obtained, and that the ETO funds permit a price within the range of other alternatives.
4. Acquire 135 MWa in fixed price power purchase agreements (PPAs) for durations of five to ten years.
5. Acquire up to 50 MWa of baseload energy tolling in place of fixed price PPAs, if required, and 400 MW of tolling capability for peak purposes.
6. Rely on the ETO to achieve 55 MWa of energy efficiency in PGE's service territory by 2007.
7. Evaluate the market potential for combined heat and power systems at customer sites.
8. Build a "virtual" peaking plant from 30 MW of dispatchable standby generation.
9. Acquire capacity through customer demand reduction programs.
10. Acquire short-term energy supply to meet the average annual energy need for direct access customers.

PGE states that it is willing to add an additional action item to initiate a discussion with Staff, renewable developers, BPA, the ETO and other stakeholders about constraints to competitive renewable development in the region. It has also communicated its willingness to include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional wind (and other) resources are accessible to PGE at a reasonable price.

Staff Recommendation

Staff recommends acknowledgement of PGE's least cost plan, as outlined in its Final Action Plan, with an exception and three conditions. The exception is that although the plan to pursue Pt WW is reasonable and should be acknowledged, the

[2] PGE also asked the Commission to acknowledge the acquisition of seasonal exchange contracts "as available and appropriate" and to acknowledge buying and selling "to balance its energy position to meet daily, weekly and monthly energy requirements." Plan at 11-12. However, we consider the acquisition of such contracts, along with purchases and sales required to balance energy requirements, to be part of the general course of business for PGE. These action items do not require acknowledgement. See Order No. 89-507.

specification that it be a cost-based resource should not be acknowledged because the Commission has not ruled on PGE's request for waiver of OAR 860-038-0080(1)(b) or made a determination in Docket UM 1066, which addresses the treatment of new generating resources.

Staff recommends that the following three conditions be placed on the Plan:

1) PGE must commit to initiate discussion with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region. PGE has agreed to this provision.
2) PGE must include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional wind (and other) resources are accessible to PGE at a reasonable price. PGE has also agreed to this condition.
3) PGE must demonstrate that it has taken reasonable measures to acquire or option cost effective transmission capacity over the Cascades before issuing its next RFP.

Participant Comments

NIPPC, ODOE, CUB, NWEC and RNP submitted written and/or oral comments regarding PGE's Final Action Plan.

CUB states that, based on analysis presented in the Plan, it is not unreasonable to select a diverse portfolio of resources such as is included in PGE's preferred portfolio. However, it expresses a strong reservation that acknowledging the Plan, under present circumstances, could lead to a situation where PGE could gain acknowledgement of Pt WW as part of a mix of resources and then acquire only Pt WW without pursuing any of the other resources in the portfolio. CUB questions whether participants would be able to challenge the decision to build Pt WW if this situation becomes reality. CUB further questions whether PGE's least cost plan is the sum of all the specific actions it identifies in its preferred portfolio, or if it is a set of individual resource actions. While CUB notes that no action plan is precisely followed, it cautions that care must be given to avoid the situation described above.

CUB is also concerned that acknowledgement of Pt WW, based on known cost assumptions, could be construed as pre-approval. If so, then the burden of proof regarding the prudence of investment in the plant could possibly be shifted from PGE to the Commission or other participants. Further, participants could potentially be precluded from questioning PGE's choice of site, technology or provider when PGE files for cost recovery of the plant.

Finally, CUB expresses concern that the RFP process is not adequate to allow for acknowledgement of a specific resource and that constraints on development of renewable resources may not have adequately been addressed, particularly given high volatile gas prices.

ODOE observes that projected load resource deficits for 2012 indicate there will be future flexibility to obtain more renewable resources between 2011 and 2016. ODOE believes that PGE should acquire or option at least 400 MW of transmission capacity before issuing its next RFP to mitigate the transmission constraints that prevent PGE from obtaining more wind resources pursuant to this IRP.

ODOE believes that PGE's approach to demand response is inappropriate and should not be acknowledged. ODOE argues that PGE should be proactive in developing and refining demand response programs for conservation and reliability. ODOE recommends that PGE incorporate the estimated effectiveness of all demand response programs in its next forecast of peak load.

Finally, ODOE believes that, independently from the IRP process, the Commission should determine how to calculate the above market cost of new renewables for the purposes of determining the amount of ETO subsidies.

RNP commends PGE for its renewable resource and energy efficiency targets described in the Plan. However, RNP encourages PGE to participate in efforts to reduce transmission, shaping and integration barriers, and to include "all environmental and risk mitigation values of renewable resources in its planning and procurement processes." It also questions whether all the risk mitigation benefits of wind resources were properly considered in PGE's evaluation process.

NIPPC proposes that the Commission require PGE to publish some aspects of its Pt WW cost assumptions and allow participants in PGE's RFP an opportunity to "beat" the Pt WW "bid." NIPPC makes this recommendation because, in its view: 1) the RFP process may not have assured participants that the RFP process was, in actuality, fair; 2) the fact that the independent observer was retained by PGE raises questions regarding whether it was, in actuality, independent; 3) the life-of-plant approach to price scoring may have penalized shorter term proposals in a manner contrary to that understood by bidders; 4) the RFP does not appear to be designed to produce bids that could realistically compete with the utility's project; 5) PGE's role as competitor and judge precludes a fair comparison of all bids; 6) it is unlikely that the Commission or Staff will have the knowledge and expertise required to evaluate the costs and risks of Pt WW and its components; and 7) a second round of bidding will provide the Commission with more information on which to assess whether PGE's Plan is the least cost mix of resources.

NWEC raised concerns regarding whether the Rate Volatility Index (RVI) used in PGE's analysis is an appropriate measure of risk, whether the cost/risk tradeoff between owning versus "renting" resources had been adequately evaluated, and whether ratemaking decisions should be settled in UM 1066 before Pt WW is acknowledged. NWEC also indicated that the Pt WW project should be delayed until gas volatility and transmission constraints have abated.

Comments on or after May 26, 2004

During the May 26, 2004 public meeting, CUB, RNP and NWEC asked the Commission to place additional conditions on the acknowledgement of PGE's Plan. Specifically, they asked that PGE be required to: 1) get into the BPA transmission queue for long-term firm transmission rights for possible future resources east of McNary; 2) participate in BPA's open season process for system upgrades and provide updates to the Commission; and 3) collect data for the January 1, 2007 report required by ORS 757.617(b) for determining whether the current level of demand side management funding, along with other programs, is showing cost-effective conservation.

On May 28, 2004, PGE submitted its response to these three conditions. PGE agreed that transmission congestion is a threshold issue inhibiting further development of renewables, but it does not support the first condition, as PGE believes such a condition is impractical. To get into the BPA queue, according to PGE, is very costly and time consuming. A resolution to the transmission issues will need the concerted efforts of utilities, BPA, developers, regulators and stakeholders working together. PGE is not willing to have such a condition placed upon it.

As for Condition 2, PGE is not sure what the participants meant by the proposal. Further, PGE does not believe that the Commission should require PGE to participate in a process that is not defined, and does not, as of yet, exist. PGE contends that the transmission conditions recommended by Staff are sufficient.

Finally, PGE agrees that more information is needed to determine whether the current programs and incentives capture all cost-effective demand-side management resources. However, PGE does not believe such a condition is appropriate for acknowledgement of its Plan. It suggests that monies collected through the Public Benefit Charge be used to support such data collection.

On June 22, 2004, PGE informed the participants that it is willing to hold a workshop within a few weeks of the Plan's acknowledgement to work with the participants to develop an opt-out proposal for large customers pursuant to ORS 757.212(3) and (4). PGE also stated that it was willing to look at possible mechanisms for PGE to share the risks and rewards of potential cost under-runs and over-runs of Pt WW with all the non-exempted customers.

On June 24, 2004, RNP informed the Commission that BPA was hosting an open season for eligible customers requesting transmission service for the West of

McNary/West of Slatt transmission path. RNP asked that PGE be required to participate in this open season process.

On June 25, 2004, PGE informed the participants that the target date for commercial operation of Pt WW has been moved from November 2006 to May 2007. On June 30, 2004, NIPPC submitted a letter to the Commission, asserting that an underbid process is "warranted now more than ever." NIPPC contends that since the project date has changed, an additional six months of time no longer jeopardizes the timeliness of the project.

OPINION

Jurisdiction

PGE is an Oregon public utility, as that term is defined in ORS 757.005, which provides electric service to or for the public.

On April 20, 1989, pursuant to its authority under ORS 756.515, the Commission issued Order No. 89-507 (Docket UM 180) adopting least-cost planning for all energy utilities in Oregon.

Requirements for Least-Cost Planning Under Order 89-507

Order No. 89-507 establishes procedural and substantive requirements for least-cost planning and provides for the Commission's acknowledgement of plans that meet the requirements of the order.

<u>Procedural Requirements</u>: At a minimum, the least-cost planning process must involve the Commission and public prior to making resource decisions rather than after the fact. *See* Order No. 89-507 at 3.

PGE solicited, received and considered both written and oral input from the public and from the Commission.

<u>Substantive Requirements</u>: The substantive requirements set forth in Order No. 89-507 are as follows:

1. All resources must be evaluated on a consistent and comparable basis.
2. Uncertainty must be considered.
3. The primary goal must be least cost to the utility and its ratepayers consistent with the long-run public interest.

4. The plan must be consistent with the energy policy of the State of Oregon, as expressed in ORS 469.010.

PGE's Plan is consistent with the substantive requirements of Order No. 89-507. We reviewed PGE's methods for evaluating different types of resources and found that all resources were compared on a consistent and comparable basis. PGE considered uncertainty by using a wide range of possible conditions and assumptions in its portfolio modeling, as well as by using the RVI mechanism. PGE selected a portfolio that reflects a favorable trade-off between least risk and least cost to ratepayers, consistent with the long-run public interest. Oregon's energy policy promotes the efficient use of energy resources and sustainability. PGE's demand side management action items, its selection of renewable resources, and its willingness to continue to work on these areas shows consistency with ORS.769.010.

Finally, we want to reiterate that under least cost planning, the risks of implementation in a cost effective manner rest with the utility. As we stated in Order No. 89-507 at 6:

> The establishment of least-cost planning in Oregon is not intended to alter the basic roles of the Commission and the utility in the regulatory process. The Commission does not intend to usurp the role of utility decision-makers. Utility management will retain full responsibility for making decisions and for accepting the consequences of the decisions. Thus, the utilities will retain their autonomy whole having the benefit of the information and opinion contributed by the public and by the Commission.

Commission Discussion

We agree with Staff's assessment that the Plan is reasonable. Therefore, we acknowledge PGE's least-cost plan as outlined in its Final Action Plan, subject to one exception and three conditions. We discuss each of these separately.

Exception: Generic Gas Resource – PGE asked for acknowledgement of Pt WW in its Plan. Some participants are concerned that by acknowledging Pt WW, this Commission is engaging in pre-approval of the resource for ratemaking purposes. This issue was discussed during the May 26, 2004 public meeting, at which PGE indicated that Commission acknowledgment of the construction or acquisition of a 350 MWa generic gas resource was acceptable. Due to the issues involved with pre-approval, and because we currently have an open docket to review how IRPs will be handled in the future (UM 1056), we choose to not acknowledge the construction of the resource at Pt WW. However, we understand that with our acknowledgement of a generic gas resource, PGE intends to build Pt WW using G-class turbine technology.

Because we do not acknowledge the construction of Pt WW, we also cannot acknowledge Action Item 2, which is as follows:

> Acquire 25 MW of duct firing capability at Port Westward for peak loads and economic dispatch.

We therefore delete the reference to Pt WW in Action Item 2, and acknowledge the revised action item.

NIPPC requested that the Commission order PGE to participate in an underbid process for Pt WW. We decline. Based on our decision to acknowledge a generic gas resource, the issue of a Pt WW underbid is moot. Further, NIPPC has not demonstrated to our satisfaction that a substantially different result would occur if we allowed an underbid process.

PGE also asked for acknowledgement of the resource as cost-based resource. As we previously noted, PGE requested a waiver of OAR 860-038-0080(1)(b) which requires all new generating resources to be included in a company's revenue requirement at market. We address this request in a separate order issued this same date. See, Order No. 04-376.

Conditions:

1. PGE must initiate discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region;

2. PGE must include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resources are accessible to PGE at a reasonable price; and

3. PGE must demonstrate that it has made reasonable efforts to acquire, retain or option cost effective transmission capacity over the Cascades before issuing its next RFP.

Although PGE agreed to the first two conditions, we want to clarify our intent of the conditions. While PGE is the moving party to organize and begin the discussions, PGE must also be evaluating the constraints to competitive renewables development in the region, and working with the participants to determine ways to remove the identified constraints. It is not enough to simply organize conversations. As for the second condition, PGE should not wait until the filing of its 2005 IRP to discuss prospectively its plans for developing transmission capacity over the Cascades. Along with outlining future plans, PGE is also expected to report in its 2005 IRP what it has done since the issuance of this order to develop transmission capacity over the Cascades.

PGE recommended modifying Staff's third condition to add the word "retain" to the list of reasonable measures it must take. Staff agreed with this addition, as long as PGE understands that simply retaining capacity is not enough to satisfy the condition. PGE should demonstrate that it has made reasonable efforts to acquire or option cost-effective capacity before submitting its next RFP. With this caveat, we adopt PGE's modification.

Conditions requested by participants: CUB, RNP, and NWEC recommended that PGE should submit a request to BPA for long-term firm transmission rights that would accommodate resources east of McNary and commit to participating in BPA's open season process for systems upgrades. PGE argued that these requirements should not be made part of the Plan. Since the time of the May 26, 2004 public meeting, we have been made aware that BPA has begun an open season for a McNary-John Day transmission project.

We decline to adopt these specific action items at this point in the process. However, in light of the three conditions we are acknowledging, we expect PGE to assess the merits of any opportunity to acquire or foster the development of transmission capacity that will make renewables more accessible to PGE and its customers. PGE will be held accountable for its decisions that affect resource costs incurred and included in future rate cases. PGE must undertake appropriate steps to address transmission constraints that inhibit its ability to obtain generation from the east side of the Cascades at a reasonable cost.

Demand Response: The Plan we are acknowledging today states that PGE will determine the expected load reductions obtained through demand buybacks at various prices, which may allow buybacks to be treated as a capacity resource. PGE also plans to issue an RFP in late 2004 for customized demand response contracts for critical peak periods. We support these activities, because we expect PGE to assess the size of different demand response resources (e.g., likely customer participation at different incentive levels) as well as the benefits (e.g., avoided generation or purchase costs during critical peak hours). We urge PGE to run more pilot programs as needed to determine customer acceptance and benefits and costs, and to offer demand response programs more widely where they appear to be cost-effective.

As for its 2005 IRP, PGE should model dispatchable demand response resources (such as direct load control and demand buybacks) as portfolio options that compete with supply-side options. Further, PGE's load forecasts should recognize the effects of nondispatchable demand response resources (such as time-of-use pricing).

Study for Cost-Effective Conservation: CUB, RNP and NWEC also ask PGE to gather data regarding demand side management. We believe that this is an important issue to be addressed in UM 1056.

Acknowledgement: There has been extensive discussion about the meaning of acknowledgement of PGE's Plan. The participants engaged in extensive discussions about PGE's IRP, and, at times, seemed to view this matter as a contested case. We hold that the meaning of acknowledgement for this Plan is no different than for any other plan. Acknowledgement of this Plan means that the Plan as a whole appears reasonable, based on the information and analysis available now. It also means that the specific resource actions, when combined with other action items, should result in "the mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs." Order No. 89-507 at 2.

Acknowledgement of this Plan does not preclude participants from challenging any of the action items included in the Plan. As stated in Order No. 89-507 at 7, "Consistency with the [least cost] plan may be evidence in support of favorable rate-making treatment of the action, although it is not a guarantee of favorable treatment." Acknowledgement of this Plan will not relieve PGE of its responsibility to prove, in a future rate proceeding, that its actions were prudent.

This order does not constitute a determination on the ratemaking treatment of any resource acquisitions or other expenditures undertaken pursuant to PGE's 2002 IRP, its IRP Supplement, or its Final Action Plan. Legally, the Commission must reserve judgment on all ratemaking issues for an appropriate contested case. We do, however, consider the least-cost planning process to complement the ratemaking process. In rate-making proceedings in which the reasonableness of resource acquisitions is considered, the Commission will give considerable weight to utility actions that are consistent with acknowledged least-cost plans. Utilities will also be expected to explain actions taken that are inconsistent with Commission-acknowledged plans.

CONCLUSION

PGE's least cost plan, consisting of the following specific action items, is acknowledged on the condition that PGE: 1) commits to initiating discussions with Staff, renewable developers, BPA, ETO and other stakeholders to discuss constraints to competitive renewable development in the region; 2) agrees to include an action item in its 2005 IRP to address how it will work with BPA and others to develop transmission capacity over the Cascades so that additional resource are accessible to PGE at a reasonable price; and 3) agrees to demonstrate that it has made reasonable efforts to acquire, retain, or option cost effective transmission capacity over the Cascades before issuing its next RFP.

The acknowledged action items are:

1. Build or acquire 350 MWa of a high efficiency gas-fired resource.
2. Acquire 25 MW of duct firing capability for peak loads and economic dispatch.
3. Acquire approximately 65 MWa (195 MW) of wind generation, provided that the necessary transmission and integration services can be obtained, and that ETO funds permit a price within the range of other alternatives.
4. Acquire 135 MWa in fixed price PPAs for durations of five to ten years.
5. Acquire up to 50 MWa of baseload energy tolling in place of fixed price PPAs if required, and 400 MW of tolling capability for peak purposes.
6. Rely on the ETO to achieve 55 MWa of energy efficiency in PGE's service territory by 2007.
7. Evaluate the market potential for combined heat and power systems at customer sites.
8. Build a "virtual" peaking plant from 30 MW of dispatchable standby generation.
9. Acquire capacity through customer demand reduction programs.
10. Acquire short-term energy supply to meet the average annual energy need for direct access customers.

ORDER

IT IS ORDERED that Portland General Electric's least cost plan, as set forth in its 2002 Integrated Resource Final Action Plan, is acknowledged in accordance with the terms of this order and Order No. 89-507.

Made, entered, and effective ______________________________.

Lee Beyer Chairman	**John Savage** Commissioner
	Ray Baum Commissioner

Back to the Ratebase

Utilities are absorbing distressed IPPs, and raising alarm bells in the process.

As a former independent power producer, George Lagassa is sympathetic to the woes of the merchant power industry. Until just a few years ago, he held the license to a micro-hydro qualifying facility (QF) in New Hampshire, so he understands what it takes to compete in a regulated-franchise industry. Yet, as the principal of Mainstream Appraisals in North Hampton, N.H., Lagassa is also a dedicated pragmatist. He sees the industry's consolidation trend as a sort of correction in the U.S. power market.

"IPPs might be squawking about fair-market value, but I'd submit that value is largely what you define it to be," Lagassa says. "If an owner is obligated to sell a plant, for whatever reason, then that asset is inherently distressed. A distressed asset, by definition, will not sell for fair-market value."

Meanwhile, 1,500 miles to the west in Oklahoma, Pete Delaney is hoping to buy one such asset. Delaney, an executive vice president at OGE Energy Corp., has his eye on the 520- MW McClain plant, now owned by the bankrupt NRG Energy. The Oklahoma Corporation Commission approved OGE's plan to acquire the plant, but the deal has been delayed by interventions at the Federal Energy Regulatory Commission (FERC).

Competitive power suppliers are crying foul, charging that OGE is freezing out competing generators, and that the utility should have conducted a competitive solicitation before deciding to acquire the McClain facility. But Delaney is quick to respond.

"It's a false belief that we can go out and get a great contract for supplies to serve our retail customers," he says. "When we look at the other supply options, buying this plant is the hands-down winner all the way around—on cost, efficiency, location, and risk."

Delaney asserts that generators within reasonable transmitting range of OGE's load don't want to tie up their output with a 30-year purchased power agreement (PPA) priced at today's depressed wholesale rates. Even if they would, such contracts today pose troublesome counterparty credit risks. "The rating agencies view long-term PPAs as debt equivalents," Delaney says. OG&E already buys $120 million of power annually under contracts with AES, Calpine, and PowerSmith Generating, but it is concerned about the prospect of exposing itself to a generator with financial difficulties. "Signing a long-term contract with a 'B'-rated entity brings substantial counterparty risk," he says.

Conversely, by acquiring the McClain plant, OGE can lock in a secure source of liquidation-priced capacity for the lifetime of the facility, which is only three years old, and generates some of the most efficient power in the region.

With his voice betraying more than a hint of frustration, Delaney asks, "If we can't buy McClain, which is clearly cheaper than building a plant, where does that leave us? Are we supposed to charge retail customers higher rates so that federal regulators can force a market solution that isn't economic?"

Another 1,500 miles to the west, Jan Smutny-Jones is experiencing a persistent sensation of déjà vu. As the executive director of the Independent Energy Producers (IEP) trade association in Sacra-

Illustration by Alex Stephen

By Michael T. Burr

No Safety Nets Allowed

Among the many issues that competitive power suppliers raise in the debate over bringing formerly unregulated power plants into the rate base is the concern over affiliate cross-subsidy. In some of the proposed arrangements, utilities are absorbing assets that are already owned by an unregulated affiliate. The question becomes whether these deals are negotiated on an arm's-length basis, and if they have the effect of charging retail ratepayers for risks incurred in unregulated markets.

"Where the utility seems to be bailing out a non-regulated subsidiary by putting a plant into the rate base, they will be accused of helping the subsidiary rather than the public good," notes David Moody, a vice president with Stone & Webster Management Consultants in Cambridge, Mass.

Such behavior will elicit uncomfortable questions from state and federal regulators, and indeed it already has. Both Ameren and Cinergy propose to re-bundle into the rate base plants that their affiliates previously operated as wholesale generators. Federal and state regulators alike have identified this approach as discriminatory.

In its ruling on Cinergy's petition, the Federal Energy Regulatory Commission (FERC) stated, "The ability of a franchised utility to assume its affiliated merchant's generation when market demand declines gives the affiliated merchant a 'safety net' that merchant generators not affiliated with a franchised utility lack. ... The safety net could be a barrier to entry that harms the competitive process in general and raises prices to customers in the long run because affiliated merchant generation with a safety net option will not be subject to the price discipline of a competitive market."

This issue is not necessarily a deal-killer, however; FERC approved Cinergy's petition, after all, but only with caveats and a promise to closely scrutinize subsequent re-bundling proposals. "The commission will in the future modify its approach to analyzing competitive effects of intra-corporate transactions of this nature," the commission stated. —*M.T.B.*

mento, Calif., Smutny-Jones was an early advocate for the potential of competition in power generation. Such reformers battled the American utility-industrial complex all the way to the U.S. Supreme Court—and won.

Or did they?

"We're seeing a very disturbing national trend that is taking several different forms," Smutny-Jones says. "Various parts of the country are taking a huge step backward."

He's referring to the growing trend toward utilities bringing formerly unregulated power assets into the regulated rate base, either directly, by acquiring or transferring ownership, or indirectly, through special-purpose affiliates and contracts. Many such deals, Smutny-Jones says, have the effect of freezing out competitive suppliers and leaving ratepayers holding the risk. Others act as a safety net, he says, for affiliated companies that have failed in their unregulated business ventures *(see sidebar above, "No Safety Nets Allowed")*.

"You need a long-term memory in this business to recall that the good-old days of cost-plus regulation weren't all that good," he says. "It's obvious that utilities would like to get back into the generation business, because it's a great deal having ratepayers trapped to cover your managerial mistakes. But that's not appropriate."

Going Vertical

Vertical integration is returning to the U.S. utility industry. The combination of illiquid wholesale markets, tighter credit requirements and a preponderance of distressed merchant plants has set the stage for utilities to acquire unregulated generation capacity to serve retail loads. And while even detractors admit that each of these transactions might have merit, they argue that the trend raises difficult questions about what supply procurement practices are appropriate in today's halfway-deregulated power market. "Without a doubt, the decades-long trend away from utility-owned generation has reversed," says Jeff Bodington, principal of financial advisory Bodington & Co. in San Francisco. *(See Figure 1, "U.S. Power Plants Sold, 2003," p. 35)*. "Now the question is, how much will we backtrack?"

In 2003, just over 1.4 GW of unregulated generating capacity was converted into rate-based assets, for the bargain price of $585 million. In the coming months, if major deals already announced proceed, at least another 5.6 GW of unregulated capacity will move into the regulated rate base. *(See Figure 2, "Building Rate Base," p. 37)*.

This trend is fueled by a variety of factors, but the key trigger in many cases seems to be the fear of blackouts. "Utilities see shortages coming," Bodington says. "In part, utilities were shocked by the Northeast blackout last year, and in particular some municipals want to island themselves so they can be insulated from regional problems. With the many difficulties in the power industry, one of the surest ways for a utility to get regulatory approval of new capacity is to put it in its rate base."

Many such deals, however, are coming under fire. The merchant power community, for example, has a litany of complaints about this trend. They argue that in general, such transactions might reduce competition by removing suppliers from the market. These deals tend to be inherently discriminatory, they say, and some of them amount to procurement *(Continued on p. 37)*

FIGURE 1 **U.S. POWER PLANTS SOLD, 2003**

Source: Bodington & Co.

As part of its asset valuation and advisory practice, Bodington & Co. tracks power plant sales transactions, and provides these data for *Fortnightly* readers by special arrangement. All data are in public domain and believed to be accurate as of Jan. 29, 2004. Unless noted otherwise, all plants: are operating or in advanced development; are located in the United States; and changed hands from January through December 2003.

Buyer	Seller	Asset(s)	State(s)	#	Gross MW	Net MW	Price ($ million)
AMP - Ohio	NEG	Bowling Green, Napoleon and Galion	Ohio	3	149	149	7
ArcLight	Aquila	Numerous QFs	Various states and Jamaica	12	643	643	301
ArcLight	York Power Funding	Big Spring wind farm	Texas	1	34	34	Not Available (NA)
Black Hills Corp.	Not disclosed	Harbor	Calif.	2	80	80	NA
Boralex	Black Hills Corp.	Seven hydro plants	N.Y.	7	80	80	186
Centennial Power (MDU Resources)	NEG (San Gorgonio)	Mountain View wind plant	Calif.	1	67	67	103
Clean Energy Systems	AES	Kimberlina	Calif.	1	6	6	1
Competitive Power Ventures[1]	Newport Generation	Fayetteville; Palestine; and Wallula	N.C.; Texas; and Wash.	4	4,820	NA	NA
Constellation	RG&E	R.E. Ginna	N.Y.	1	495	495	401
Delta Power	Gregg Enterprises	Central Power & Lime (Brooksville)	Fla.	1	150	150	NA
Denver City Energy Associates	NRG	Mustang Station	Texas	1	483	242	NA
Dominion Resources	Wisconsin P&L and WPS	Kewaunee	Wisc.	1	545	545	220
Dominion Virginia Power	Calpine	Gordonsville	Va.	1	240	120	32
Dominion Virginia Power	Edison International	Gordonsville	Va.	1	240	120	32
Exelon[2]	British Energy	Clinton, TMI Unit 1, Oyster Creek	Pa.	3	2,500	1,250	277
FPL Energy	Enron	Cabazon, Green Power, Sky River and Victory Garden Phase IV	Calif.	1	106	106	82
FPL Energy	Orion Energy	Wind project near Evanston	Wyo.	1	144	144	NA
GE Structured Finance	Calpine	King City	Calif.	1	115	69	82
GE Structured Finance	Cogentrix	Green Country	Okla.	1	810	729	97
GE Structured Finance	Mirant	Birchwood	Va.	1	242	120	71
Goldman Sachs	Cogentrix	Numerous plants	Various	26	3,300	3,300	2,415
Goldman Sachs	El Paso Merchant	East Coast Power (Linden)	N.J.	1	940	940	456
Green Power Energy	Cogentrix	Kenansville cogeneration plant	N.C.	1	38	38	NA
GTCR Golder Rauner[3] and Invenergy	TECO Power Services	Hardee	Fla.	1	370	370	115

(Continued on p. 36)

Buyer	Seller	Asset(s)	State(s)	#	Gross MW	Net MW	Price ($ million)
Highstar Renewable Fuels	Duke Energy	Duke/UAE Ref-Fuel plants	Conn., Mass., N.J., N.Y. and Pa.	6	400	200	306
Hoosier Energy	Williams	Worthington	Ind.	1	170	170	67
Intergen	AES	Mountainview[1]	Calif.	1	1,056	1,056	30
Kauai Island Utility Co-op	Dominion Resources	Naphtha-fired plant	Hawaii	1	26	26	40
Ormat	Covanta	Heber, SIGC, Mammoth geothermal plants	Calif.	3	140	120	214
Ormat	Far West Development	Steamboat 2 & 3 geothermal plants	Nev.	2	35	35	33
Ormat	US Energy	Steamboat 1 and 1A geothermal plants	Nev.	2	17	17	2
Pomifer Point Funding LLC	Calpine	Auburndale	Fla.	1	150	105	86
PPM Energy	Golden NW Aluminum	Klondike windpower	Ore.	1	24	24	17
PPM Energy/Shell Oil	GE Wind Energy	Colorado Green Wind Project	Colo.	1	162	162	212
Private Energy	NiSource	Lakeside Energy, Cokenergy, North Lake Energy, Portside Energy, Ironside, Harbor Coal	Ind.	6	444	444	335
Puget Sound Energy	EPCOR Power Development Corp.	Fredericksen	Wash.	1	275	137	76
Reservoir Capital Group	Exelon Generating	Numerous former Sithe Energies plants	Various	15	941	470.5	75.8
Reservoir Capital Group	Sithe	Naval Station, Training Center, Naval Oxnard, North Island; Greeley, Kenilworth; and a 157-MW merchant plant	Calif.; Colo.; Canada	6	214	214	46
Rockland Capital Investment Partners	Aquila	Prime Energy	N.J.	1	66	33	NA
Salt River Project	Reliant	Desert Basin	Ariz.	1	588	588	289
Synex Energy Resources	New World Power	Wolverine Power hydro plants	Mich.	4	11	11	1
TECO[4]	Panda Energy	Union Power Station, Gila River	Ariz.	2	4,500	2,250	250
Tenaska	Dynegy	Paris, Frontier, Texas; Ferndale	Wash.	3	1,305	132	NA
Transalta	El Paso Merchant	CE Generation geothermal and gas-fired plants	Ariz., Calif., N.Y., Texas	13	820	410	240
UGI Development	Allegheny Energy Supply	Conemaugh Station	Pa.	1	1,711	83	51
Wabash Valley Power Association	Duke Energy	Vermillion	Colo.	1	640	160	44
Total	**Transactions:**	45		**147**	**30,292**	**16,643**	**$7,291**

Notes: (1) Project(s) in advanced development; (2) Exelon exercised right of first refusal after FP&L had agreed to acquire the assets for same terms; (3) Purchaser assumed project debt in addition to paying $115 million in cash; (4) Purchased for accounting write-offs worth approx. $250 million.

Back to the Ratebase

(Continued from p. 34)

decisions being made without the benefit of a transparent and fair approach to determining least-cost options. Many argue that a competitive solicitation is the only way to know whether a given transaction is the optimal one for ratepayers.

"You'd think states would want to do bidding to make sure ratepayers are getting the best deal," says Julie Simon, vice president of policy with the Electric Power Supply Association (EPSA). "Instead, they are taking the utility's word for it." The problem, Simon argues, is that utilities have a vested interest in owning generating capacity rather than contracting for it.

"They make a return on equity by putting assets into their rate base, and that's how you get into a situation where ratepayers are paying more than they should," she says. "This is a serious problem because without bidding, you can't know if these deals are valid."

Questions involving the prudence of utilities' procurement plans fall within the purview of state regulators, and these very regulators have approved affiliate transactions in which power assets are being acquired or transferred into ratebase without using a competitive solicitation process. The growing list of states that have approved such deals include California, Indiana, Kentucky, Oklahoma, and arguably Missouri. Merchant power advocates also are closely watching proceedings in Arizona, Florida, Georgia, Louisiana, Pennsylvania, and Wisconsin.

"If the state regulators determine that retail ratepayers won't get ripped off, then the FERC should defer to that determination," says Larry Eisenstat, a partner with Dickstein, Shapiro, Morin & Oshinsky, and head of its electric power practice. "But the FERC can't defer on the question of how these deals affect the wholesale market." Indeed, FERC is taking a close look at some major rate-basing proposals currently on its docket. Examples include the aforementioned OGE Energy/McClain acquisition, as well as: (1) Southern California Edison's (SCE) proposed assimilation of the 1,054-MW Mountainview project now under construction; (2) Ameren's plan to rate-base two plants totaling nearly 550 MW; and (3) Cinergy's plan to integrate 712 MW of unregulated assets into the rate base of PSI Energy. The Cinergy plan has received FERC's provisional blessing and seems to be nearing the finish line.

The Ameren and Cinergy deals are particularly noteworthy because they would transfer assets that are already owned by affiliates of the acquiring utilities. Others, including the SCE-Mountainview transaction and another deal proposed by Duquesne Light, involve affiliates acquiring third-party assets and selling the output to the affiliated utility. Such transactions prompted FERC to apply strict standards for determining if an affiliate transaction is fair and legitimate.

At a conference hosted by Merrill Lynch in late January, FERC Chairman Pat Wood confirmed that the commission is looking closely at rate-basing deals and their effects on competitive wholesale markets.

"I will admit some concern about the acquisition of temporarily distressed generation assets by local utilities that would otherwise be buying under a long-term contract," Wood said. "We're concerned about not only deals with affiliates, but deals that make power markets more concentrated as opposed to

FIGURE 2 — BUILDING RATEBASE

During 2003, utilities integrated about 1.4 GW of formerly unregulated generating assets into their ratebase, either by taking direct ownership or through contracts with special-purpose affiliates. As of Feb. 1, 2004, similar proposed transactions total 5.6 GW.

Buyer	Seller	Plants (#)	Net MW	Transaction Value ($ million)
Transactions in 2003				
AMP - Ohio	NEG	3	149.0	7.0
Dominion Virginia Power[1]	Calpine	1	120.0	31.5
Dominion Virginia Power[1]	Edison International	1	120.0	31.5
Puget Sound Energy	EPCOR Power Development Corp	1	137.0	76.4
Salt River Project	Reliant	1	588.0	288.5
GenTex (LCRA)	Calpine[2]	1	272.5	150.0
Total		**8**	**1,386.5**	**$585**
Pending Transactions				
Ameren	AmerenUE	2	548.0	257.9
Cinergy (PSI)	Cinergy (CinCap)	2	712.0	450.0
Entergy[3]	Cleco	1	725.0	170.0
Oklahoma Gas & Electric	NRG Energy	1	400.4	160.0
Southern California Edison	InterGen	1	1,054.0	NA
Arizona Public Service[4]	Pinnacle West Energy	4	1,710.0	NA
Duquesne Light	WPS Resources	1	449.5	120.0
Total	-	**12**	**5,598.9**	**$1,157.9**

Notes: (1) Dominion sources report that company acquired assets whose PPAs were already in rate base; (2) Calpine also got a 250 MW tolling agreement with LCRA through end of 2004; (3) Official purchase price not disclosed; Transaction value sourced from business press reports; (4) APS sought to transfer Pinnacle West merchant assets to rate base in 2002 rate case; final outcome pending results of RFP process.

Sources: Bodington & Co.; Author's research more disaggregated. That means less competition, and it ultimately means that we have to back into a regulated market, which I don't think any of us wants to do."

Such sentiments being expressed at FERC give utilities pause, but they insist that bringing unregulated plants into the rate base will prove to be irrelevant from a wholesale-market perspective. "If you ran the market-power numbers, they would come out the same whether the utility purchased a power plant or its output under a long-term contract," says Ed Comer, general counsel of the Edison Electric Institute (EEI) in Washington. "In either case, they'd control the power. The critical question is whether the deal serves retail customers."

Merchant power advocates, however, argue that such statements belie utilities' real motives—to build ratebase and squelch competition. "Currently there is no merchant market in the United States," Smutny-Jones says. "Everything is predicated on contracts. When you have a major buyer refusing to enter into power purchase contracts, [nearby merchant plants] sooner or later are bound to become distressed. It's a self-perpetuating prophecy."

The conflicts between utilities and merchant generators—not to mention federal and state regulators—seem unlikely to abate any time soon, but signals coming from both camps suggest that room exists for compromise. During 2004, the industry and its regulators will be challenged to find such compromise solutions.

For example, the California Public Utilities Commission (CPUC) approved Edison's Mountainview acquisition because the commission saw an imminent and growing need for power capacity in SCE's service territory. At the same time, though, CPUC found "vexing weaknesses" with the structure of SCE's proposed transaction. So the commission attached caveats to its approval to insulate ratepayers from some of the risks SCE proposes to undertake.

Such a give-and-take approach might allow regulators to approve individual transactions, while also addressing lingering concerns about competition and market power.

"If [FERC] really is concerned with protecting the wholesale market, it should take steps to ensure that when transactions such as this occur, they occur on the condition that the wholesale market remains or becomes viable," Eisenstat says. For example, if a utility is not a member of a regional transmission organization (RTO), the commission could condition approval on the utility joining an RTO, upgrading its transmission network or agreeing to take measures that would enhance wholesale competition. Such measures might entail including all available suppliers in its economic dispatch processes, or agreeing to competitively procure all of its future energy requirements.

"If a utility has market power, it should only be permitted to maintain that power if it's clear that any effort to exercise it has been or will be mitigated," Eisenstat says.

Many utilities, likewise, will probably be open to compromises that satisfy FERC's market concerns. "We offered upfront to upgrade transmission to help import capacity," Delaney says. "We're not trying to frustrate competition in wholesale markets. We've actively led and supported the development of an RTO here. We simply want to do our job of serving retail customers as effectively as we can."

Recovering Lost Ground

Clearly, the stakes are high on both sides of the issue—which is why the subject of rate-basing unregulated plants will generate a lively debate in the months ahead. For utilities and state commissioners, supply margins, reliability, and credit factors are at issue. For merchant players, the industry's very survival might be at risk.

"If FERC can't show that all generators are competing on a level playing field, then investors will be extremely reluctant to invest in anything but the regulated side," Eisenstat says.

Such concerns might seem misplaced in an industry currently suffering from too much investment in facilities, but this overbuilt situation won't last forever. Within just a few years, many regions will begin feeling the pinch of load growth. In the meantime, how procurement policies evolve could determine the ability of unregulated generators to access these growing markets—a disturbingly familiar situation for veteran independent power advocates.

"While Edison says [Mountainview] is a one-off deal, they are very active in the state legislature trying to get changes in the law that will make it easier for them to build power plants and recommit ratepayers for up to 30 years of stranded costs with no meaningful regulatory review," Smutny-Jones says. "If that's the road we are heading down, it will be a disaster."

Compromise solutions seem unlikely to satisfy all stakeholders or to cure what ails the merchant power market. But if implemented thoughtfully, they could be constructive. By allowing utilities to pursue attractive rate-basing deals, while helping merchant generators to obtain commensurate access to a deeper marketplace, compromise options might actually allow the competitive wholesale market to recover some of the ground it has lost in the past two years.

If that happens, maybe Smutny-Jones will finally be able to shake off that annoying sense of déjà vu.

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PUC-IR-50 **(HECO)**

HECO SOP, Exhibit A, at 27 states:

> For CHP resources, the Companies plan to use a competitive procurement process. ...

Please explain in detail the differences between an RFP and a competitive procurement process, and explain why HECO considers the latter to be more appropriate for CHP resources.

HECO Response:

A competitive procurement process can utilize a variety of approaches to meet its objectives, including issuing requests for proposals ("RFPs"), pre-qualifying bidders, or using strategic vendor alliances. As stated in HECO T-1 pages 32-33, in Docket No. 03-0371, HECO's objectives of its competitive procurement process for combined heat and power (CHP) system equipment are, among others, (1) to ensure provision of quality CHP products and services, (2) to standardize equipment and designs, (3) to achieve efficiency in the equipment selection process, and (4) to obtain cost savings for the utility and its ratepayers, especially over the life cycle of the CHP installation. HECO may use a variety of processes to accomplish the needs of a particular project.

As for the process itself, HECO is still in the stages of developing it, but we are considering use of elements from various approaches to procurement, including, pre-qualifying bidders, used of strategic alliances, and equipment bidding. The appropriateness of approach will depend somewhat on the project itself. For example, very large CHP systems may warrant use of equipment bidding due to the cost of equipment. Medium size projects might be bid or assigned to a more limited group of pre-qualified vendors offering either packaged or engineered systems. Small CHP systems might be procured via a strategic alliance with a qualified vendor of packaged systems. (HECO T-1 pp 32-33, Docket No. 03-0371.)

PUC-IR-52 **(All parties)**

Ref: CA SOP at 20.

> Competitive bidding is one [mechanism for procurement]. The others include auctions, standard offers and selection through direct negotiations as well as approaches that combine elements of these mechanisms…

a. Should the Commission consider mechanisms like auctions, standard offers and others identified by the CA as part of this competitive bidding docket?

b. Identify those situations where other methods such as standard offers or direct negotiations might be appropriate alternatives to competitive bidding.

<u>HECO Response:</u>

a. No. The other mechanisms identified by the CA such as auctions or standard offers are more applicable for short-term resources and/or the procurement of standard products (i.e., 7x24 firm power, etc.). Web-based auctions for power are becoming more common, with bidders allowed to compete to supply power supply products to utilities. Such auctions are based on price only, which generally requires that the product bidders are competing for is standardized. These methods (i.e., auctions and standard offers) are not applicable if the utility is looking for long-term power with different operational characteristics from new generating units.

b. As noted above, the predominant case in which standard offers or auctions would be most applicable would be if the utility is soliciting bids for standard products, with the characteristics of the product defined up-front and with the bidding based on price only. HECO has also described a situation in which utilities have offered standard offer contracts for certain types of resources (i.e., QFs and small power producers) with the price based on the cost of the lowest cost option selected in its competitive bidding process. Some utilities have also used a "Competitive Negotiations" process for evaluating resource options. Under this approach, the utility still issues an RFP, reviews the bids received, selects a short-list and conducts direct negotiations with a number of bidders designed to have the bidders compete against one another during the negotiations process. Bids are eliminated during the negotiation process if they are not able to specifically renegotiate the bid to add value to the utility. Competitive negotiations can be an effective process but it is time consuming to complete.

PUC-IR-53 **(All Parties)**

Ref: HECO-CA-IR-34 at 67.

What are the benefits and drawbacks to a utility offering utility-controlled sites for 3rd parties to develop in the competitive bidding process? What terms and process should apply?

HECO Response:

Should competitive bidding for certain forms of new generation be implemented in Hawaii, it is the position of the HECO Companies that the utility should have the discretion to offer a utility-controlled site to developers in a competitive bidding process. For example, if the utility is soliciting bids for a turnkey option, it may be appropriate for the utility to offer its site because the utility will eventually own and operate the plant. Such discretion will also maximize the utility's flexibility to tailor an RFP to best meet changing system needs, or possibly facilitate the development of particularly desirable supply-side resources, such as renewable energy technologies which can be highly dependent upon site location with limited site alternatives (e.g., wind energy and pumped storage hydro). From the perspective of the non-utility developer, perhaps the primary advantage of a utility offering its site for third parties to develop in the competitive bidding process is that the development costs and efforts for the bidder can be minimized. In addition, the utility can generate revenues from the sale or lease of the site.

However, offering utility controlled sites has a number of potential challenges to overcome or disadvantages from the perspective of the utility and its customers that should not be ignored. First, utility-controlled sites are valuable assets that have been secured to benefit the customers over the long term. To ensure long-term reliability of supply, it may be beneficial for the utility to maintain site control to ensure power generation resources could be constructed to meet system reliability requirements. This is particularly true in Hawaii, where the number of sites that are available to site new generation are very limited. Second, offering utility-controlled sites may reduce the flexibility of the utility to perform crucial parallel planning for a utility-owned option to backup the unfulfilled commitments of IPP developers of generation. Hawaii utilities do not have the option to acquire power from other jurisdictions, or even other islands. Third, offering utility-controlled sites may reduce the full value hoped to be gained in a competitive solicitation process. Bidders are not encouraged to develop creative options to meet Hawaii's needs, but instead will be more likely to select the utility site possibly limiting the range of resources options bid. For example, a pumped storage hydro developer may decide not to bid if a utility-controlled site located, for illustration purposes, in Campbell Industrial Park was made available in the RFP. And fourth, there may be complex legal issues associated with the sale or lease of a utility-controlled site, such as ensuring that the bidder and not the utility absorbs any environmental liability associated with the site.

PUC-IR-54 **(HECO)**

HECO SOP, Exhibit A at 21 states:

> The above mentioned roles for the host utility are common in most RFP processes and are recognized by regulators and third-party bidders as a reasonable role for the host utility. Recent competitive bidding dockets have recognized the role of the utility and have supported an active role for the host utility.

a. Is HECO aware of any other jurisdictions where the host utility plays a different role in the RFP process?

b. If so, please provide examples including, for each, the utility, the approach used, and the outcome of the RFP.

HECO Response:

a. HECO is not aware of any jurisdictions where the host utility plays a different role in the RFP process than the roles mentioned in HECO's SOP, Exhibit A at page 21. There may be cases where the role of the utility does not include all the roles identified by HECO. For example, not all utilities compete in the solicitation process with a self-build option. Duke Power, for example, has issued several RFPs for power supply. To the best of HECO's knowledge, Duke has not included a self-build option in any of the solicitation processes. Also, Hydro-Quebec has retained an accounting firm to accompany it during the Call for Tenders process. The firm is responsible for conducting communications with bidders throughout the process. All inquires from bidders go through the accounting firm as well as responses to bidders. All bids are sent to the accounting firm and the bids are opened by Hydro-Quebec and the Accounting firm in public.

b. See the response to (a) above.

PUC-IR-55 **(All Parties)**

Ref: CA SOP at 56 states.

> The Commission should ensure that a utility's RFP design and bid package materials are developed in a manner that will ensure an appropriate measure of transparency.

a. **(CA)** Please specify the components of "appropriate measure of transparency."

b. **(All Parties)** What features should be included in the RFP design and bid packages to provide enough information about the selection process so as to maximize participation by the widest possible range of bidders?

HECO Response:

a. This IR is not assigned to HECO, HELCO or MECO.

b. The bidders primarily want to know "how can I be successful in this process". From the perspective of bidders, they want to know the following information:

   1. The method used by the utility to evaluate the bids.
   2. The factors that are most important to a utility (i.e., identification of the evaluation criteria and the importance of each).
   3. The price and non-price factors of importance
   4. The methodology for conducting the price analysis and the factors included in the price analysis.
   5. The contract terms required and the risk provisions of the contract.
   6. The ability of bidders to ask questions about any aspect of the solicitation process and receive prompt responses.
   7. Is the utility going to compete with a self-build option. What is the status of the utility's project.
   8. Is there a preferred location to site the project.

9. Does the schedule for identifying a site, negotiating a letter of intent on the site, prepare a bid, and submitting the bid provide sufficient time to allow for a completed bid.

PUC-IR-56 **(All Parties)**

a. Should the Commission have an active role in the RFP development process?

b. Should an independent consultant be hired to provide input and recommendations to the utility and Commission regarding the drafting of the RFP? If so, who should fund the cost of the independent consultant?

c. Should the utility independently develop the RFP (subject to approval by the Commission prior to its issuance)?

d. Should the utility hold a workshop with potential bidders and other interested parties prior to the release of the RFP, and potentially incorporate comments and suggestions into the final RFP?

HECO Response:

a. The Commission should not have an active role in the RFP development process. As noted, HECO suggests that the utilities meet with the Commission on a regular basis during the RFP development and implementation stages. The Commission can choose to approve the RFP before it is issue, but this could add significantly to the time to conduct the RFP process.

b. The utility may decide to hire a consultant to assist it in drafting the RFP. However, that decision will be up to the host utility. Since the utility will make the unilateral decision whether to retain a consultant, the utility will fund the cost of the consultant.

c. The utility should independently develop the RFP, and should meet with the Commission prior to issuance of the RFP. Pre-approval of the RFP could minimize later disputes, but would add significantly to the time to issue an RFP.

d. The option to conduct a workshop with potential bidders and others prior to release of the RFP is becoming more common in the industry. In some cases, workshops are held during the IRP phase of the process only. In other cases, workshops are conducted to review and discuss the RFP documents. Incorporating comments and suggestions from bidders and other interested parties into the final RFP, should be at the discretion of the utility, so as not to delay the issuance of an RFP. HECO should play a major role in the competitive bidding process, including: (1) designing the RFP documents, evaluation criteria, and power purchase agreement; (2) managing the RFP process, including communications with bidders; (3) evaluating the bids received; (4) selecting the bids based on the established criteria; (5) negotiating contracts with selected bidders; and (6) competing in the solicitation process with a self-build option, if feasible. HECO SOP at 8.

PUC-IR-57 **(All Parties)**

Ref: HREA SOP at 13; HECO-HREA-IR-11; CA SOP at 3; HECO-CA-IR-3.

a. Should different types of resources (e.g., renewable resources, new technologies, and traditional resources; supply-side and demand-side resources, as-available v. firm capacity resources; and distributed resources) compete through the same RFP? or

b. Should there be separate RFPs issued for different types of resources, which would all be issued simultaneously, to address a particular need? or

c. Should a solicitation be targeted to a particular resource for a particular need, such that there will only be one RFP issued at one time

d. Where different types of resources compete through the same RFP, what criteria should be used to evaluate the different benefits of different resources?

e. Discuss the benefits and drawbacks of issuing one RFP for different types of resources versus targeted solicitations that seek a particular resource?

HECO Response:

a. HECO has proposed that supply-side resources only are eligible to compete in the solicitation process. Different types of supply-side resources could compete through the same process. However, it may be more efficient and less burdensome for the bidders to respond to RFP documents tailored to their specific needs.

b. As stated in response to (a), it would be less burdensome for bidders of different categories of resources (i.e., conventional supply-side and renewable resources) to respond to slightly different RFP documents tailored to their needs. For example, Central & SouthWest Services sent out two RFP documents: one to bidders who indicated they were bidding a conventional supply-side resource and one for renewable resources. Even within the renewable resource RFP, different information was requested from different bidders (e.g., a wind project developer would have to provide a wind resource assessment at its site while a hydro-electric project developer would be required to provide water flow data). However, it is not reasonable to issue separate RFPs for each renewable resource option.

c. Utilities should have the option to target specific resources if required or issue an RFP with broad-based eligibility requirements. For example, while Central & SouthWest Services issued all-source RFPs and all-supply source RFPs, the Company also issued a wind-only RFP to provide resources for its green marketing program.

d. In cases where different types of resources compete through the same RFP, some utilities will revise the evaluation criteria slightly to reflect the important characteristics of each resource. The two major non-monetary criteria that are subject to revision are resource adequacy/supply and environmental. Please see HECO's response to PUC-IR-62 as an example of how one utility incorporates environmental factors in its solicitation process.

e. Developing and issuing one RFP for all types of resources reduces the burden on the utility to develop multiple documents and contracts and instead shifts the burden to the bidder to respond accordingly. In fact, some RFPs actually coded questions for different types of resources within the same RFP to direct the responses of these different resource options. Issuing multiple RFPs (HECO interprets the question of targeted RFPs to mean multiple RFPs, such as separate documents for conventional supply-side and renewable resources) eases the burden on the bidder to sift through the RFP and interpret the information it must provide. Separate RFPs allow bidders to focus on the specific information they must provide.

PUC-IR-58 **(HECO)**

HECO SOP, Exhibit A at 3 states:

> While natural gas-fired combined cycle options have been the dominant form of capacity contracted through competitive bidding processes, other resources have been selected as well. Contracts for renewable resources have been increasing and many projects have been selected either through all supply source RFPs or targeted solicitations.

Please provide examples, including underlying RFP documents, where renewable resources have been selected through all supply source RFPs.

HECO Response:

Portland General Electric selected a portfolio of projects through its recent RFP process, including two wind projects. The Portland General Electric's RFP is voluminous. Two copies of the RFP will be provided to the Commission, and one copy to each party or participant by separate transmittal.

Hydro-Quebec recently completed a Call for Tenders for wind generated electricity and contracted for nearly 1,000 MW of installed capacity. While this was not an all-supply source RFP, it nevertheless represented a successful renewable resource RFP.

PUC-IR-59 **(All Parties)**

a. Who should determine what the required qualifications for bidders (e.g. creditworthiness, reputation, experience) should be?

b. Should the required qualifications of potential bidders be clearly outlined in the RFP?

c. Should a pre-qualification process be conducted on bidders before accepting bids?

d. If yes, who should pre-qualify the bidders?

HECO Response:

a. The utility developing the RFP should be responsible for developing the evaluation criteria, including the required qualifications of bidders.

b. Yes. The RFP should generally state the required qualifications of potential bidders based on the criteria established by the host utility. For example, the RFP could state that the utility prefers project developers with demonstrated experience in developing and operating similar projects with a record of bringing projects on-line as scheduled, and with an investment grade credit rating.

c. HECO has not determined whether a pre-qualification process is necessary. This is one RFP process option that should be considered at the appropriate time. While there have been competitive bidding processes that include a pre-qualification stage, these processes are in the minority. In many RFPs, the minimum requirements or threshold stage of the evaluation effectively replaces the pre-qualification stage.

d. If there is a pre-qualification process included in the solicitation process, it is HECO's view that the host utility should be responsible for pre-qualifying the bidders.

PUC-IR-60 **(All Parties)**

a. Should the Commission have an active role in the development of the bid evaluation criteria?

b. Should an independent consultant be hired to provide input and recommendations to the utility and Commission regarding the bid evaluation criteria? If so, who should fund the cost of the independent consultant?

c. Should the utility independently establish the bid evaluation criteria (subject to approval by the Commission prior to its issuance)?

d. Should the utility hold a workshop with interested parties prior to the release of the RFP, to discuss the bid evaluation criteria so that bidders clearly understand how their bids will be evaluated?

<u>HECO Response:</u>

a. No. The Commission should <u>not</u> have an active role in the development of the bid evaluation criteria. The utility should maintain responsibility for developing the bid evaluation criteria and such criteria should reflect the unique circumstances of each utility. As noted in response to PUC-IR-56, HECO would meet with the Commission during the RFP design process to update the Commission on the process.

b. Please see the response to PUC-IR-56(b)

c. Please see the response to PUC-IR-56(c)

d. Please see the response to PUC-IR-56(d).

PUC-IR-61 **(All Parties)**

Ref: HECO-CA-IR-12(b)states.

> Some of the important factors may include, but are not limited to, generation system reliability and capacity requirements, opportunities to secure low-cost energy, renewables requirements, emissions impacts, location, risk exposure and rate impacts.

The above response identifies certain factors that should be considered in the review of competitive bid responses. Please identify any other factors that should be considered during the review of the competitive bids.

HECO Response:

There are two types of issues addressed in the CA's statement referenced above. The first issue pertains to the overall policy directives associated with the utility's resource planning and procurement process. Several of these issues may be decided or addressed during the IRP process and before the solicitation process is initiated. These may include the states renewables policy, emissions implications (i.e. green houses gases), and possibly rate impacts.

The second issue deals with the criteria and methodology used in the bid evaluation process. For a list of potential non-price criteria or factors common to solicitation processes, please see HECO's response to PUC-IR-32. These non-price criteria or factors are designed to assess the quality of the bid relative to the important characteristics identified in the RFP and should be considered during the review of individual bids.

PUC-IR-62 **(All Parties)**

HECO SOP, Exhibit A, at 30 states:

> To ensure that all reasonable options are effectively considered, there should be no unreasonable restrictions on sizes and types of projects. It is generally preferable that all types of eligible projects (e.g. supply-side options) have a fair opportunity to compete. (emphasis in original)

And HECO SOP, Exhibit A, at 32 states:

> Price-related evaluation criteria are the predominant selection criteria. Non-price criteria are used to ensure the project or portfolio is viable and feasible but price is usually the ultimate determinant.

What mechanisms, if any, are appropriate to account for the non-monetary costs or benefits of different types of resources?

HECO Response:

There are mechanisms to account for the non-monetary costs or benefits of different types of resources. The most obvious method is to account for non-monetary factors in the evaluation process. Most utilities have developed evaluation processes that include both monetary and non-monetary elements. HECO listed a number of non-monetary factors in the response to PUC-IR-32. These non-monetary factors can include score ranges based on project size, resource type, location, fuel type, stability of the price stream, etc. The importance of each non-monetary factor will be based on the views and needs of the individual utility or bidding guidelines.

As an example, the Portland General competitive bidding process contained environmental impacts for specific resources in the evaluation process. The environmental scores were based on a table originally contained in Oregon's bidding rules from 1991, updated to reflect recent information. The Table was included as Appendix T to the Portland General Electric RFP, which is attached to HECO's response to PUC-IR-58. For example, using this approach, the damage factors for coal were the highest, while renewable projects were the lowest.

While this is one approach, other utilities will attempt to quantify such attributes as environmental costs and benefits, transmission impacts, etc. through their integrated evaluation process.

PUC-IR-63 **(HECO)**

HECO SOP, Exhibit A, at 42 states:

> In some RFP processes, an Independent Observer or Independent Reviewer is retained by the utility (in some cases with the approval of the Commission) to observe and/or audit the bid evaluation and selection process. The utility conducts the evaluation of the bids and is responsible for selecting the winners and negotiating contracts. If an Independent Observer is requested, HECO recommends that the role of the Independent Observer be to manage correspondence between the utility and bidders, review and audit the results of the evaluation process, and advise the utility if there are any fairness issues.

a. Is there a distinction between Independent Observer and Independent Reviewer?

b. If so, please explain the distinction and the roles of each; and the advantages and disadvantages of each.

HECO Response:

a. While the specific functions or requirements of the independent party may vary slightly for different solicitations, the terms independent observer or independent reviewer are generally used interchangeably.

b. Please see the response to a. above

PUC-IR-64 **(All Parties)**

a. Who should hire the Independent Consultant – the utility or the Commission?

b. Should the Independent Consultant develop bid evaluation criteria and make a recommendation for the project award without input by the utility? [Ref. HREA Response to HECO-IR-9 at 11] Or can the input be from all parties?

c. Is an Independent Consultant required for all competitive bids – or only those where a utility affiliate does not compete?

HECO Response:

a. In most cases, the utility has selected the Independent Consultant. In many cases, the Commission will review and sign off on a list of possible candidates and the utility will select from the list. HECO recommends a similar approach should there be a need for an Independent Consultant. See HECO SOP, Exhibit A at page 42.

b. No. The role of the Independent Consultant has not involved developing the bid evaluation criteria or making a recommendation for the project award. HECO believes it is the appropriate role of the utility to undertake the evaluation of bids and make recommendations about the selection and negotiation of winning bids and is not a function that should be "outsourced". See HECO SOP, Exhibit A at page 42. HECO has an obligation to serve its customers with reliable service and can only do so if it has the ability to make resource procurement decisions. As HECO responded in HREA-HECO-IR-11, HECO does not agree with HREA's proposed role for an Independent Contracting Agent and feels such a role is totally inappropriate for such a major resource decision.

c. An Independent Consultant should not be required in cases where a utility or affiliate are not offering a competitive option. This is typical of industry practices.

PUC-IR-66 **(All Parties)**

Ref: CA SOP at 59; HECO-CA-IR-64.

a. If the Commission adopts the guidelines recommended by the Consumer Advocate, and implements these concepts, are these sufficient to ensure that a utility's participation in the competitive bid process is fair?

b. What are the advantages and disadvantages of adopting these guidelines?

c. What other safeguards should be adopted?

HECO Response:

a. HECO appreciates the CA's recognition the utilities' "obligation to serve", which extends to ensuring that they can provide customers a reliable electrical supply "if all else fails." CA SOP at page 59. The CA's guidelines attempt to provide a balance between encouraging utilities to seek options from the market when economical to do so and recognizing that there may be instances where the utility believes it is not beneficial or economical to do so. But to be consistent with the CA's recognition of utilities' obligations, HECO believes that the CA's proposed guidelines for a utility's submission of a bid in its own solicitation need to be adjusted to be fair to the utility's customers and the utility itself while maintaining the potential benefits that competitive bidding may provide.

- The CA's proposed guidelines appear to create a presumption that the host utility competitive bidding should be the default unless there is a clearly demonstration that the utility can better achieve objectives without competitive bidding. CA SOP at page 59. HECO's position differs in that, if competitive bidding is adopted, the process should only be open to supply-side resources, with DSM options being ineligible and CHP projects worked through a competitive procurement process. HECO SOP, Exhibit A at page 26.

- The thrust of the CA's guidelines appears to limit the utility's full participation in the bid process. See CA SOP at pages 59 and 60. In contrast, HECO's position is that the "host utility as a primary stakeholder must play a major role in the competitive bidding process," including competing in the process with a self-build option. HECO SOP, Exhibit A at page 21. HECO provides specific examples of how to ensure fairness when the host utility participates in bidding, including the use of an independent observer where appropriate (HECO SOP, Exhibit A at page 42) and mechanisms such as requiring the utility bid to be submitted before other bids in order to avoid possible conflicts or appearances of conflicts. These proposals would promote fairness while allowing the utility to fully participate as a bidder in the process.
- The CA also states that a utility competing in its own RFP should be held to terms consistent with contractual terms "such as availability" it would hold a third party supplier for the same resource. CA SOP at page 60. In general, contract provisions are not included in the bid evaluation process, so it is not likely a utility project will enjoy any advantage over a non-utility project with regard to bid evaluation. Any issues associated with implementation of the contract would need to be discussed in more detail. While contracts for power from IPP projects are generally stand-alone performance-based contracts, the utility builds plants to meet system load. As a result, it is difficult to equate IPP performance-based contracts with utility project arrangements.

b. The advantage of guidelines is that they provide an indicator to bidders about the rules of the game and provide bidders a comfort level that the process will be undertaken in a fair and equitable manner. The most significant disadvantage is the determination of the details surrounding the guidelines.

c. HECO has provide suggested guidelines that provide the benefits of competitive bidding where appropriate while promoting actual fairness and the appearance of fairness for all parties. See HECO SOP, Exhibit A at pages 41 to 43.

PUC-IR-67 **(All Parties)**

Ref: HECO-CA-IR-48 states:

> The Consumer Advocate recommends that each electric utility should be expected to design bid evaluation processes that are specific to the circumstances of each competitive solicitation, and in keeping with "best practices" in the industry.

To the extent that this approach could potentially allow a utility to tailor specific bid evaluations to favor certain bidders, what safeguards can be implemented to prevent this?

HECO Response:

HECO expects that many components of the RFP will not vary significantly from solicitation to solicitation. The general criteria, the steps involved in the evaluation process, the process for selecting a short-list of bidders, the questions or information requested of bidders, and the contract negotiation process will not vary significantly from one solicitation to the next unless a major change in the industry occurs. As an example, Hydro-Quebec Distribution has issued four Call for Tenders for long-term power supplies: (1) a 1,200 MW firm supply-side Call for Tenders; (2) a 100 MW biomass Call for Tenders; (3) a 1,000 MW wind-generated electricity Call for Tenders; and (4) a 350 MW cogeneration Call for Tenders. All these resources had different characteristics and requirements, yet the evaluation process, overall criteria, and contact negotiation process, etc. were the same or very similar. However, the Call for Tenders documents were revised to reflect the unique characteristics of the resources solicited, the requirements of the bid were specified, and the criteria and weights were changes to reflect the resource. For example, in the wind Call for Tenders, local economic development impacts were included in the evaluation, which was not part of other Call for Tenders. Also, while more sophisticated production cost modeling was used for the supply-side Call for Tenders, simpler spreadsheet models were used for the wind Call for Tenders, since the resource characteristics were very similar and there was not an opportunity to dispatch the resource to minimize overall system cost.

While some changes may be necessary for each solicitation, the basic structure, procedures, and processes will likely be consistent. To avoid any concerns about tailoring the specific bid evaluations to favor certain bidders, probably the most frequently utilized safeguard is to receive Commission approval before issuing the RFP. This is common practice in the industry. For additional safeguards, see HECO response to PUC-IR-23.

PUC-IR-68 **(All Parties)**

Ref: HECO-CA-IR-68.

The Consumer Advocate suggests a generic policy intended to balance the needs for "transparency" and confidentiality during the bid review process. Please provide specific suggestions on how this balance can be met.

<u>HECO Response:</u>

To ensure a fair and competitive solicitation process which encourages participation of bidders, probably the most important factor is maintaining confidentiality of bid information. If bidders and any other interested parties were free to sit in the room with bid evaluators during final bid selection and negotiations as the CA indicates, the process would deteriorate into chaos. First, bidders would not want competitive information made public about their project. Second, bidders would second-guess the evaluator at every step of the way in an attempt to maximize their score. It is a process that is not workable and is akin to the early self-scoring competitive bidding processes that resulted in significant litigation and many failed projects.

HECO's proposed solution is to design a reasonably transparent bidding process, whereby bidders are informed in the RFP of the process used to evaluate and select bids, the evaluation criteria of importance to the utility, and the contract provisions of importance. See HECO SOP, Exhibit A at pages 42 to 44. Bidders need to know in general "how can I win the bid" but should not be in a position to influence the evaluation and selection process. As one solution to this issue, in other competitive bidding processes, the utility may meet with Commission staff to provide updates on the process. Furthermore, utilities generally develop thorough documentation of the evaluation and selection process for each bid, which can be reviewed with Commission staff at the end of the process. Ultimately, the Commission has the review authority to approve the contract resulting from the competitive bidding process.

As noted in HECO's SOP, another solution is for the utility to retain an independent reviewer or observer that oversees the results of the process, if a utility bid is presented. See HECO Response to PUC-IR-23.

PUC-IR-69 **(All Parties)**

HECO-CA-IR-10.

a. Should bidders' track record on past projects be a factor in selection and if so, how significantly should it be weighted? What elements of the track record should be considered?

b. Will according significant weight to a track record cause newer generators without track records or smaller independent companies to lose out to more established utility affiliates or large independents? Should the Commission be concerned about this impact?

<u>HECO Response:</u>

a. One of the typical non-monetary evaluation criteria included in many RFPs is the experience (track record) of the bidder. Bidders are generally required to provide a description of the projects they have developed and operated, the availability factor for the units they have developed and operated, and whether or not the unit entered service on schedule as planned. In addition, many RFPs also request information about the members of the bidders' project team and their experience with developing and operating similar projects. The weight attributed to this criterion is difficult to determine at this point. The weights for each criterion are usually established based on an iterative process involving members of the utility's bid evaluation team and taking into account the importance of this criterion relative to other non-price criteria.

b. It is difficult to determine at this point if affording significant weight to track record or experience will negatively impact the ability of smaller independent companies or newer companies from competing. This depends on the relative importance of the track record criteria to other criteria and the components of the track record criteria considered. For example, a newly formed company comprised of personnel with significant experience in developing and operating similar power projects may score as well in this category as an established IPP with similar experience.

The process for developing the appropriate criteria can be somewhat time consuming but is nevertheless a very important task in the development of the RFP. It is also important to note that the criteria of importance for one utility may differ significantly for another utility, depending on location, resources, market access, access to energy infrastructure, etc. This is one of the reasons why HECO cautions that merely adopting another utility's RFP process may be fraught with problems and may not reflect the criteria of importance to Hawaii utilities. The process described by HECO for the design and development of the RFP is important to ensure the criteria of importance are reflected appropriately in the RFP.

PUC-IR-70 **(HECO and KIUC)**

Ref: HREA-HECO-IR-21.

a. Have any of the utilities offered or provided a tolling option for fuel to any existing IPPs?

b. Have any of the utilities otherwise offered or had experience with fuel sharing, or with sharing of fuel storage or transport expenses with an IPP?

c. If the utilities were to provide tolling options for fuel to the IPPs, might the associated additional fuel purchases by the utility (i.e., as opposed to not purchasing the volume of fuel required by the IPPs) be beneficial to the utility in negotiating future fuel contracts?

HECO Response:

a. Portland General Electric, BC Hydro, and PacifiCorp all offered bidders of new generation a tolling option. In these cases, the utilities offered to purchase the gas and transport the gas to the IPP, relieving the IPP of the obligation. There have been a number of cases on the Mainland whereby a marketer offered a tolling option to a power generator. However, HECO is not aware of any cases where a utility has offered a tolling option to an existing IPP.

b. There have been a number of instances whereby gas utilities or combination gas and electric utilities have agreed on fuel sharing arrangements. For these options to be beneficial, the IPP should have dual fuel capability. While fuel sharing arrangements may vary, a typical structure is for the gas utility to have the right to call on all or a portion of the fuel supply and transportation contracted for by the IPP for its project for 10 days per year. During those 10 days, the IPP runs on the alternate fuel. The gas utility pays for the alternative fuel as well as compensates the IPP for the option to call on the fuel during the coldest days. The gas utility gets a peaking service to meet peak day requirements. One example is the arrangement between Bay State Gas Company in Massachusetts and MassPower, an IPP project also in Massachusetts.

c. Yes. There may be several opportunities for arrangements whereby tolling options offered by utilities can be beneficial to the utility's customers. First, a tolling option allows the utility to be a larger participant in the fuel market, enhancing the utility's ability to negotiate more economically attractive arrangements. Second, the tolling option could allow the utility to utilize its portfolio of fuel supply and transportation assets more efficiently. For example, Portland General had excess pipeline capacity and was looking at tolling as a way to better utilize its transportation capacity to reduce the costs to its customers.

PUC-IR-71 **(All Parties)**

a. Should the Commission have an active role in the development of the purchase agreement?

b. Should an independent consultant be hired to provide input and recommendations to the utility and Commission regarding the drafting of the purchase agreement? If so, who should fund the cost of the independent consultant?

c. Should the utility and the winning bidder independently develop the purchase agreement (subject to approval by the Commission prior to its issuance)?

<u>HECO Response:</u>

a. Development of the power purchase agreement is generally a role not typically performed by the Commission. The utility issuing the RFP generally takes the lead in developing the power purchase agreement. HECO has negotiated and managed several IPP agreements and this experience would be advantageous for developing the model power purchase agreement.

b. It is typical that an outside counsel or attorney experienced in the design of power purchase agreements would be a most likely candidate to assist in the development of the PPA. The decision to have an outside counsel or staff attorney draft the agreement is generally made by the host utility. HECO does not believe there should a requirement that an independent consultant be hired to provide input and recommendations regarding the PPA, but should be retained at the utility's discretion.

c. In most cases, the final contract agreed to by the utility and winning bidder will be different from the model PPA included in the RFP. It is not possible for the winning bidder to independently develop the model PPA, which must be prepared before the bids are received.

PUC-IR-72 **(All Parties)**

Should a copy of the proposed purchase agreement be included as part of the issuance of the RFP?

HECO Response:

HECO has suggested that a copy of the proposed purchase agreement should be included as part of the issuance of the RFP. See HECO SOP, Exhibit A at pages 31, 36 and 41. As stated on page 41 of HECO's Statement of Position:

> "Including a model power purchase agreement in the RFP document provides valuable information to bidders deciding whether or not to bid and what level of risk is required. Bidders can then reflect that risk in their proposal."

PUC-IR-73 **(All Parties)**

Ref: HREA SOP at 10-11; HREA-HECO-IR-11.

Should there be a standard model purchase agreement to be used for all purchases (with possible minor modifications), or should the purchase agreement for each new transaction be separately drafted?

HECO Response:

A large number of contract provisions (i.e., boiler plate provisions) could be standard for virtually any contract. However, there will be modifications required depending upon the type of resource and project structure (i.e., standard PPA, turnkey arrangement, tolling arrangement, etc.). For example, Hydro-Quebec has issued Call for Tenders for baseload supply-side resources, biomass, wind-generated electricity, and cogeneration projects. Many of the provisions of the contracts have remained constant from Call to Call, with modifications dependent upon the type of resource and any unique requirements imposed by the regulator.

PUC-IR-74 **(All Parties)**

Ref: HECO-CA-IR-17.

a. To what extent should the price and non-price terms of a purchase agreement be subject to subsequent negotiation with the utility and amendment, if the changes are beneficial to both parties and the ratepayers?

b. What should be the conditions placed on further negotiation?

c. If the utility affiliate is the winning bidder, do your answers to (a) or (b) change, or are there safeguards that would allow for further negotiation with the utility?

<u>HECO Response:</u>

a. In most RFP processes, bidders are informed that the price will be fixed in the contract based on the bid. There may be opportunities to negotiate non-price terms to enhance the value of the contract for both parties. Examples of such provisions that may be open for negotiation include fuel supply arrangements and project operating characteristics. An IPP may be willing to offer the utility more flexibility if the plant can accommodate such operating flexibility in exchange for the utility agreeing to other non-price considerations.

With regard to contract amendments after the project is operational, most power contracts do not contain re-opener provisions which provide either party the right to renegotiate provisions of the contract. There are rarely "free options" in a power purchase agreement. However, there may be cases where both parties agree to renegotiate provisions of the contract if it is beneficial to both parties. HECO is sensitive to the potential benefits of renegotiations. As HECO noted it is SOP, given the long-term nature of the contract and likely technology changes over the contract term, HECO would value an option in the contract that allows HECO to request the IPP to retrofit its unit to burn another fuel if fuel market costs and resource availability change over time. Such an option is practical for a utility-owned unit but may be more costly and less practical for an IPP.

b. The contract negotiation process can be a protracted, drawn-out process if it is in the best interests of the IPP to extend the process. In some RFPs, utilities have stated that if a contract cannot be negotiated within 60-90 days, the utility has the right to terminate negotiations and begin negotiations with the next best bidders. Such a provision encourages bidders to be more punctual about contract negotiations.

c. If the utility affiliate is the successful bidder, the responses to (a) and (b) do not change. The affiliate, like any other IPP, would be required to satisfy the requirements of its lenders, and therefore would abide by the same terms and conditions as any IPP.

PUC-IR-75 **(All Parties)**

Ref: CA SOP at 61 states:

> ...the Commission should make explicit that costs would be recoverable through rates on a "pass-through" basis if incurred through an approved contract that results from an RFP issued in response to approved competitive bidding process.

Are there any circumstances where the Commission might disallow costs resulting from an approved contract that results from an RFP and if so, what are they?

HECO Response:

HECO is not aware of any cases in which costs have been disallowed for a contract secured as a result of a competitive bidding process. The use of a competitive bidding process is usually a demonstration that all reasonable resource options have been considered and the lowest reasonable cost is selected through this process. As a result, the competitive bidding process should provide a true market test of the price of power in the market. HECO would expect that costs incurred from projects selected through a competitive bidding process should be recovered through rates.

PUC-IR-76 **(All Parties)**

Ref: HECO-CA-IR-19(b).

a. In the future, how should we evaluate to what extent the competitive bid process has been "successful" - what are the specific factors that can and should be recorded and evaluated?

b. Should we set target values for these factors, such that continuation or amendment of the competitive bid process may be contingent on meeting these target values?

c. What is the appropriate process and time frame for review of the success of the competitive bid process?

<u>HECO Response:</u>

a. There is no definitive formula for determining whether a process has been successful or not. Certainly, if the competitive solicitation process led to a large number of reliable, low cost bids, from a variety of resources, resulting in a successful power contract, with bidders satisfied that the process was fair and equitable, the process can be deemed a success. This outcome would underlie the essence of bidding. However, a process with only a few reliable low cost bids from a limited number of resource options might be deemed successful as well. Other "measures of success" could be (1) the number (or lack thereof) of meritorious complaints filed by unsuccessful bidders regarding the bidding, evaluation or selection process where such complaints require Commission involvement for resolution; (2) the number of meritorious complaints filed by successful bidders regarding interpretation of PPA terms and conditions where such complaints require Commission involvement for resolution; and (3) the impact on system reliability resulting from an increasing amount of purchased power on the system.

b. HECO does not believe it is feasible to target values for most of these factors. Such factors are more subjective in nature. In addition, there are a number of extraneous factors that could influence the perceived success of a solicitation process. For example, the nature of the power market in Hawaii (i.e., small market with limited opportunities, higher cost resources, limited fuel options, no interconnections). While system reliability may be quantifiable, the causes of the changes in reliability as well as the amount of the contribution of each cause will be difficult to definitively establish. With respect to the number of complaints requiring Commission involvement to resolve, certainly the goal is to achieve zero. However, given the complexity of the bidding and evaluation process (which involves some subjective judgment), the goal of zero complaints may not be realistically achievable. It may be possible to quantify the number of complaints requiring Commission involvement before and after a competitive bidding process is implemented. However, some judgment will need to be applied as to whether such complaints would have arisen even without a competitive bidding process.

c. HECO suggests that rather than attempt to develop metrics to assess whether a competitive solicitation process is successful or not, the Commission and the utility should develop a "lessons learned" assessment at the end of the process (after contract approval) if the goal is to improve the process over time.

PUC-IR-77 **(All Parties)**

Ref: CA SOP at 56 states:

> If a utility can demonstrate that it is doing a particularly good job in resource procurement, the Commission should consider an increase to its allowed return. Conversely, poor performance will require the consideration of a reduction.

a. What criteria should be applied to determine whether a utility is doing a "good job" in competitive resource procurement?

b. What factors, such as savings or added efficiencies, would a utility have to demonstrate to qualify for an added rate of return?

c. **(All parties except CA)** Do you agree that an increase in return is justified for a utility that successfully implements competitive bidding?

HECO Response:

a. HECO is unsure what the CA meant by "doing a particularly good job in resource procurement", and asked for clarification of the term "best practices". HECO believes that the CA may evaluate its implementation of competitive bidding as "good", if it adheres to "best practices". The CA noted that it "has not defined the 'best practices' that would apply to a competitive solicitation of any particular type." HECO/CA-IR-4. At this time, HECO does not have a definitive "criteria" which can be used to evaluate the implementation of competitive bidding. Key issues to be discussed in this docket include (1) what competitive bidding process, if any, should be implemented, and (2) how should competitive bidding procedures be developed. HECO SOP at 1. The future resolution of these key issues will help to shape the criteria by which competitive bidding implementation is judged.

b. At this time, HECO is unable to provide details which can clarify the statement extracted from the CA's SOP. HECO believes that it is too preliminary to speculate on possible adjustments to Rate of Return on Rate Base, without first answering the key issues described in response to subpart a. It should be noted that the issue of ratemaking was not specifically mentioned in the PUC's Order which opened the instant docket, and at this point, HECO has not directed its resources to analyzing alternative ratemaking design(s).

c. HECO has not explored ratemaking incentives as one of the key issues of this docket (see list of key issues, HECO SOP at 1).