

STATE OF RHODE ISLAND
BEFORE THE PUBLIC UTILITIES COMMISSION

IN THE MATTER OF NATIONAL GRID'S :
STANDARD OFFER PORTFOLIO : **Docket No. 4041**
PROCUREMENT PLAN FOR 2010 :

Joint Rebuttal Testimony of

TIMOTHY DANIELS
AND
DANIEL ALLEGRETTI

On Behalf of
CONSTELLATION NEWENERGY, INC. AND
CONTELLATION ENERGY COMMODITIES GROUP,
INC.

August 14, 2009

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1 **Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

2 **A.** My name is Timothy Daniels and my business address is 810 7th Avenue, Suite 400, New
3 York, New York 10019.

4 **A.** My name is Daniel Allegretti and my business address is 1 Essex Drive, Bow, New
5 Hampshire 03304.

6 **Q. HAS CONSTELLATION ENERGY COMMODITIES GROUP, INC. ("CCG") AND
7 CONSTELLATION NEWENERGY, INC. ("CNE") SUBMITTED PRIOR
8 TESTIMONY IN THIS PROCEEDING?**

9 **A.** Yes. We submitted and circulated to parties in this proceeding on June 24, 2009 the Direct
10 Testimony of Timothy Daniels for consideration by the Rhode Island Public Utilities
11 Commission ("Commission"), on behalf of and Constellation NewEnergy, Inc. ("CNE") and
12 Constellation Energy Commodities Group, Inc. ("CCG") (collectively, "Constellation"), in
13 order to provide an analysis of Narragansett Electric Company's ("National Grid") proposed
14 revised Standard Offer Service ("SOS") procurement plan filed on April 29, 2009.

15 **Q. HAS MR. ALLEGRETTI TESTIFIED PREVIOUSLY IN THIS PROCEEDING?**

16 **A.** No, he has not.

17 **Q. PLEASE DESCRIBE MR. ALLEGRETTI'S POSITION WITH CONSTELLATION.**

18 **A.** He is a Vice President of Energy Policy with Constellation.

1 **Q. WHAT ARE MR. ALLEGRETTI'S RESPONSIBILITIES AS VICE PRESIDENT OF**
2 **ENERGY POLICY FOR CONSTELLATION?**

3 **A.** He is responsible for representing Constellation's retail and wholesale commodity business
4 interests on matters related to regulatory and government affairs throughout New England,
5 New York and the Mid-Atlantic regions.

6 **Q. WHAT ARE MR. ALLEGRETTI'S EDUCATIONAL BACKGROUND AND**
7 **EXPERIENCE.**

8 **A.** His resume is attached as an exhibit to this testimony, as Exhibit No. 2.1.

9 **Q. DOES MR. ALLEGRETTI CONCUR WITH AND ADOPT AS HIS OWN THE**
10 **STATEMENTS OF MR. DANIELS IN HIS JUNE 24, 2009 TESTIMONY?**

11 **A.** Yes, he does.

12 **Q. WHAT WERE THE RECOMMENDATIONS IN CONSTELLATION'S DIRECT**
13 **TESTIMONY IN THIS PROCEEDING?**

14 **A.** In our Direct Testimony Mr. Daniels recommended that the Commission approve National
15 Grid's proposed 2010 SOS procurement plan based upon the proposed Full Requirements
16 Service ("FRS") procurement structure ("FRS Structure") without any determination of
17 moving to a managed portfolio approach ("Managed Portfolio Approach"). With respect to
18 National Grid's proposal to enter into long-term renewable contracts, Mr. Daniels noted that,
19 at the time his Direct Testimony was filed, the issue was the subject of pending legislation
20 that was awaiting the Governor's signature in order to be passed into law; he recommended
21 that the Commission hold off on making a determination on the issue of long-term renewable
22 contracts until it received final guidance from lawmakers.

1 **II. PURPOSE OF REBUTTAL TESTIMONY AND CONCLUSIONS**

2 **Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

3 **A.** In this Rebuttal Testimony, we address positions and statements made in the direct testimony
4 of Richard S. Hahn, on behalf of the Rhode Island Division of Public Utilities and Carriers
5 (“RIDPUC”), comparing a FRS Structure to Mr. Hahn’s preferred Managed Portfolio
6 Approach.¹

7 **Q. WHAT ARE YOUR CONCLUSIONS WITH RESPECT TO MR. HAHN’S**
8 **TESTIMONY?**

9 **A.** Generally, we conclude that Mr. Hahn’s statements in favor of a Managed Portfolio
10 Approach and against Mr. Daniel’s Direct Testimony are unsupported in the record and
11 incorrectly or incompletely portray both a Managed Portfolio Approach’s characteristics as
12 well as the arguments presented in Constellation’s Direct Testimony. Through our
13 arguments herein, we maintain and provide additional support for Constellation’s position
14 that a FRS Structure will best meet the needs of National Grid’s SOS customers.

¹ See *Direct Testimony of Richard S. Hahn on Behalf of the Rhode Island Division of Public Utilities and Carriers*, Commission Docket No. 4041 (submitted July 22, 2009) (“RIDPUC-Hahn Direct”).

1 **1. Mr. Hahn’s Statements in Favor of a Managed Portfolio Approach Are**
2 **Unsupported in the Record and Incorrectly or Incompletely Portray a Managed**
3 **Portfolio Approach’s Characteristics.**

4 **Q. WHAT ARGUMENTS DOES RIDPUC WITNESS HAHN USE TO SUPPORT HIS**
5 **BELIEF THAT HIS PROPOSED MANAGED PORTFOLIO APPROACH WILL BE**
6 **MORE APPROPRIATE THAN THE CURRENT FRS STRUCTURE TO SERVE THE**
7 **SOS REQUIREMENTS OF NATIONAL GRID’S CUSTOMERS?**

8 **A.** A summary of Mr. Hahn’s statements promoting his Managed Portfolio Approach over the
9 use of a FRS Structure can be found at page 27 of his testimony.² There, Mr. Hahn states
10 that:

11 (a) “In assembling any portfolio, it makes sense to diversify the contents of the portfolio
12 among various available products”;³

13 (b) “Long-term contracts can help stabilize prices in the future and facilitate the development
14 of renewable projects that can contribute to RES compliance”;⁴

15 (c) “The layering and laddering of shorter term purchases can smooth out fluctuations and
16 result in more stable prices over time”;⁵

17 (d) “Buying block products instead of Full Requirements Service contracts can help reduce
18 the risk premiums contained in the price of those products”;⁶ and

19 (e) “Leaving an open position, the portion of the portfolio supplies by spot market purchases,
20 can effectively deal with load fluctuations and any migration or switching that might
21 occur.”⁷

² RIDPUC-Hahn Direct at p.27 (lines 9-19).

³ RIDPUC-Hahn Direct at p.27 (lines 11-12).

⁴ RIDPUC-Hahn Direct at p.27 (lines 12-14).

⁵ RIDPUC-Hahn Direct at p.27 (lines 14-15).

⁶ RIDPUC-Hahn Direct at p.27 (lines 15-17).

1 **Q. HOW DO YOU RESPOND TO THIS REASONING?**

2 **A.** At the outset, Mr. Hahn’s statements above are just that – statements for which Mr. Hahn
3 provides little or no evidence for support, and which Mr. Hahn seems to ask the Commission
4 to accept as true despite the lack of any evidentiary support. Nevertheless, as we detail
5 below, each of Mr. Hahn’s statements is, in fact, incorrect or, at best, incomplete.

6 *a. A FRS Structure will “diversify the contents of the portfolio” serving SOS*
7 *better than Mr. Hahn’s Managed Portfolio Approach.*

8 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT “IN**
9 **ASSEMBLING ANY PORTFOLIO, IT MAKES SENSE TO DIVERSIFY THE**
10 **CONTENTS OF THE PORTFOLIO AMONG VARIOUS AVAILABLE**
11 **PRODUCTS”?**⁸

12 **A.** The best way to “diversify the contents of the portfolio” that meets National Grid’s SOS
13 requirements is not to buy each of the products that makes up SOS supply separately, as
14 proposed under Mr. Hahn’s Managed Portfolio Approach, but to effectively ladder the
15 purchase of supply contracts in both timing of procurement and term of supply contracts.

16 **Q, WHAT DO YOU MEAN BY “LADDER” THE PURCHASE OF SUPPLY**
17 **CONTRACTS?**

18 **A.** The term “ladder” refers to staggering the terms of the FRS procurement contracts such that
19 the individual contracts will expire at different times.

20 **Q. DOES LADDERING THE PROCUREMENT CONTRACTS PROVIDE**
21 **RATEPAYERS WITH PROTECTION FROM PRICE FLUCTUATIONS?**

22 **A.** Yes. A carefully structured procurement process using “laddered” contracts and staggered
23 procurement dates best serves to mitigate the impacts of price fluctuations in market prices

⁷ RIDPUC-Hahn Direct at p.27 (lines 17-19).

⁸ RIDPUC-Hahn Direct at p.27 (lines 11-12).

1 from year to year, thereby achieving the very stability that is appropriate for National Grid's
2 Residential and Small Commercial SOS customers. Both a FRS Structure such as that
3 proposed by National Grid, as well as Mr. Hahn's proposed Managed Portfolio Approach
4 have included a staggered schedule with a variety of supply terms, but a FRS Structure
5 achieves such diversity more effectively.

6 **Q. PLEASE EXPLAIN HOW A FRS STRUCTURE ACHIEVES SUCH DIVERSITY**
7 **MORE EFFECTIVELY.**

8 **A.** A FRS Structure provides for a diversity of potential suppliers by attracting a number of
9 wholesale bidders to a procurement for FRS products, who each competes to serve a portion
10 of National Grid's SOS requirements at the lowest price. Each of these suppliers may obtain
11 its supply from a diverse portfolio of supply from resources and markets in New England and
12 throughout the United States, managing all of the risks and costs associated with such diverse
13 supplies as efficiently as possible at a fixed cost for the term of its SOS supply contract with
14 National Grid. Each of these suppliers, moreover, has the opportunity to develop and utilize
15 innovative and diverse methods to achieve efficiencies in managing such load. As a result,
16 National Grid's SOS consumers get all of the benefits associated with a diverse and extensive
17 marketplace without the risks and costs of being tied to one particular generation resource.

18 On the other hand, under a Managed Portfolio Approach, Mr. Hahn would have
19 consumers directly bear the risks and costs associated with: (1) being tied with one particular
20 generation resource (whether through contracts with renewable or other types of generators)
21 on a long term basis, representing an increased megawatt-hour commitment to a single
22 generation source rather than a diversity of resources; (2) being directly subject to the

1 fluctuations of spot market purchases through “an open position” as discussed in more detail
2 later in our testimony; and (3) being entirely reliant on and subject to the risks of
3 mismanagement by only one portfolio manager – the utility – which we also explain later in
4 our testimony.

5 **Q. IS THERE ANY ADDITIONAL RECENT EVIDENCE AVAILABLE FOR THE**
6 **COMMISSION’S REVIEW THAT SUPPORTS YOUR CONCLUSIONS**
7 **REGARDING THE DIVERSITY ACHIEVED BY RELIANCE ON COMPETITIVE**
8 **BIDS FOR FULL REQUIREMENTS PRODUCTS?**

9 **A.** Yes. An independent study regarding utility load procurement was issued last year by the
10 Analysis Group (“Analysis Group Study”), a well-respected energy and economic consulting
11 firm, in order to address Pennsylvania’s transition to a competitive market structure.⁹ The
12 Analysis Group Study’s findings, however, apply equally well to Rhode Island’s – or any
13 other state’s – SOS procurement discussion. The Study – conducted by Dr. Susan F.
14 Tierney, a nationally recognized energy policy expert, former Assistant Secretary for Policy
15 at the U.S. Department of Energy, and former Commissioner at the Massachusetts
16 Department of Public Utilities – points out specifically that a FRS Structure:

17 taps into the abilities and skills of different players to develop different and
18 innovative strategies to meet and adapt to power supply conditions as they
19 change in the future. *This provides a diversity advantage to consumers.* It
20 passes risk from consumers and the utility that is serving as their supply
21 conduit over to the third party suppliers.¹⁰

22 We have attached as Constellation Exhibit 2.2 to our Rebuttal Testimony a copy of the
23 Analysis Group Study.

⁹ See *Pennsylvania’s Electric Power Future: Trends and Guiding Principles*, Susan F. Tierney, Ph.D., Analysis Group (2008) (“Analysis Group Study”), attached hereto as Constellation Exhibit 2.2.

¹⁰ Analysis Group Study at p.11 (*emph. added*).

1 ***b. Long Term Contracts for renewable projects may be a part of National***
2 ***Grid’s supply portfolio regardless of the procurement approach that the***
3 ***Commission adopts.***

4 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT “LONG-TERM**
5 **CONTRACTS CAN HELP STABILIZE PRICES IN THE FUTURE AND**
6 **FACILITATE THE DEVELOPMENT OF RENEWABLE PROJECTS THAT CAN**
7 **CONTRIBUTE TO [RENEWABLE ENERGY SUPPLY] COMPLIANCE”?**¹¹

8 **A.** First, Mr. Hahn seems to suggest that Long Term Contracts for renewable projects will only
9 provide the benefits he assumes under a Managed Portfolio Approach, ignoring entirely the
10 fact that Rhode Island law now mandates the procurement of Long Term Contracts for
11 renewable projects irrespective of the procurement approach the Commission approves for
12 the supply of SOS requirements. Moreover, to the extent that Mr. Hahn wishes to include in
13 National Grid’s SOS supply any Long Term Contracts above and beyond those procured
14 pursuant to the statutes and rules being developed by the Commission, we would note that
15 the use of any such *other* Long Term Contracts will hinder rather than help in meeting SOS
16 customers’ interests.

17 **Q. PLEASE EXPLAIN WHY THE USE OF ANY OTHER LONG TERM CONTRACTS**
18 **WILL HINDER RATHER THAN HELP IN MEETING SOS CUSTOMERS’**
19 **INTERESTS.**

20 **A.** Bidders in competitive solicitations may include in their trading portfolios some portion of
21 supply that is obtained through a long-term relationship. However, to specify a portion and
22 length of time for Long Term Contracts as part of SOS procurement may very well result in
23 *higher* rather than lower prices. The experience of regulators and utilities in this country
24 implementing the Public Utility Regulatory Policies Act of 1978 (“PURPA”) is a sobering

¹¹ RIDPUC-Hahn Direct at p.27 (lines 12-14).

1 reminder of the perils of trying to predict the future and obligating ratepayers to long-term
2 investments. PURPA required that utilities enter into long-term (20 years or more) power
3 purchase agreements (“PPAs”) based on forecasts of “avoided costs” determined at the time
4 of entering the PPAs. These forecasts later turned out to be well above the market cost of
5 power and the contracts became part of billions of dollars in stranded costs allocated to
6 customers.

7 **Q. DOESN'T THE RECENTLY PASSED RENEWABLE LONG TERM CONTRACTS**
8 **LAW¹² ALREADY REQUIRE NATIONAL GRID TO ENTER INTO LONG TERM**
9 **CONTRACTS FOR A SUBSTANTIAL PORTION OF THE STATE'S ELECTRIC**
10 **DEMAND.**

11 **A. Yes, the Law** The Law requires National Grid to enter into commercially reasonable
12 renewable Long Term contracts over the next four years totaling approximately 25 percent of
13 Rhode Island's total demand. Based on Constellation's analysis, these contracts could cost
14 over \$2 billion to the state's electric customers. The Law in and of itself represents by far the
15 most ambitious renewable energy Long Term contracting procurement plan in the Northeast.

16 **Q. IF THE COMMISSION NEVERTHELESS DESIRES TO HAVE NATIONAL GRID**
17 **ENTER INTO LONG TERM CONTRACTS FOR RESIDENTIAL AND SMALL**
18 **COMMERCIAL CUSTOMER SUPPLY, ARE THERE PARAMETERS THAT YOU**
19 **WOULD RECOMMEND?**

20 **A.** As detailed below, if the Commission believes it is absolutely necessary to specify Long
21 Term Contracts (beyond those renewable purchases that the State already mandates) as part
22 of a procurement process, in no case should such contracts be greater than five years in
23 length, if such contracts are for energy only; contracts for other energy-related products
24 should be limited to no more than two to three years in length. The wholesale market overall

¹² R.I. Gen. Laws § 39-26.1

1 is not sufficiently liquid to recommend contracts with term lengths greater than five years.
2 This is due in large part to the fuel price uncertainty, regulatory and political risk and the
3 long term cost of credit in these extended transactions. An illiquid market for these extended
4 contracts results in a dearth of product offerings due to a lack of buyers and sellers. This, in
5 turn, results in higher transaction costs to procure energy than in shorter term markets that
6 have greater liquidity. Greater liquidity in a market (such as that in shorter term markets)
7 means there are many buyers and sellers, which leads to competitive prices and smaller
8 transaction costs for procurement purposes. This creates greater incentives for buyers and
9 sellers to develop and trade energy products with innovative structures that are competitively
10 priced. Bidders obtaining supply from such competitive, liquid markets will pass the benefits
11 of more competitive market prices and innovative structures directly to consumers through
12 more competitive bids for SOS supply, as is the case under a FRS Structure.

13 Currently there exists a fairly liquid trading market five years out for energy products
14 only. However, while the energy-only markets may be sufficiently liquid to support energy
15 only contracts five years forward, such liquidity is not necessarily present in the capacity,
16 ancillary services and renewable markets (all of which are necessary to supply SOS) for
17 contracts more than two to three years in length, raising costs to provide energy services for
18 contracts with terms longer than that duration.

19 **Q. WHAT OTHER CHALLENGES BESIDES MARKET LIQUIDITY FACTOR INTO**
20 **YOUR RECOMMENDATION THAT CONTRACTS BE NO LONGER THAN FIVE**
21 **YEARS IN LENGTH?**

22 **A.** We can provide an example. If a bidder commits to a supply contract with National Grid
23 over a term of six years, for instance, and market prices for energy in fact decrease in Year 6

1 of the contract, there may be political pressure exerted to try and abrogate or undermine such
2 longer-term contracts, which in Year 1 were procured at competitive market prices, but may
3 be above then-current market prices in Year 6. Moreover, for National Grid, the longer the
4 term of the contract, the greater the risk of customer frustration and migration away from
5 SOS due to changing market prices and regulatory uncertainties – a result that will lead to
6 stranded costs, as explained in Constellation’s Direct Testimony. To be clear, suppliers
7 accept and must account for the risks that market prices decrease over the term of a contract.
8 Such risks are far more pronounced with a contract term of more than five years, but may be
9 highly mitigated through a competitive FRS Structure, as the costs of SOS will be more
10 closely tied to changing market prices. FRS Structures will also smooth out such changes in
11 market prices through laddered and staggered contracts, all while continuing to offer reliable
12 supply.

13 *c. A FRS Structure will “smooth out fluctuations and result in more stable*
14 *prices over time” better than Mr. Hahn’s Managed Portfolio Approach.*

15 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT “THE**
16 **LAYERING AND LADDERING OF SHORTER TERM PURCHASES CAN**
17 **SMOOTH OUT FLUCTUATIONS AND RESULT IN MORE STABLE PRICES**
18 **OVER TIME”?**¹³

19 **A.** As we explain above, *both* the current FRS Structure *as well as* Mr. Hahn’s proposed
20 Managed Portfolio Approach utilize a staggered schedule with a variety of supply terms.
21 However, a FRS Structure will more effectively smooth out fluctuations and provide
22 stability, due to its reliance only on fixed-price contracts for Residential and Small

¹³ RIDPUC-Hahn Direct at p.27 (lines 14-15).

1 Commercial Customers, without the use of an “open position” as proposed in Mr. Hahn’s
2 Managed Portfolio Approach.

3 **Q. PLEASE EXPLAIN.**

4 **A.** A FRS Structure responds to retail market developments – including the potential for
5 increased customer migration – by placing such risks on wholesale suppliers and letting them
6 be efficiently priced and managed through large competitive markets. If events occur that
7 warrant changes to load supply portfolios, such decisions are left with the wholesale
8 suppliers as portfolio managers – the entities best equipped to make such decisions – while
9 such suppliers provide to National Grid and its customers a fixed price product. Under a
10 Managed Portfolio Approach, however, flexibility is achieved by leaving “open positions” in
11 National Grid’s supply portfolio, as described by Mr. Hahn.¹⁴ Based on his proposed
12 “Procurement Structure & Plan” illustrated at Exhibit RSH-8, it appears that Mr. Hahn
13 recommends that fully *10 percent* of National Grid’s portfolio for Residential and Small
14 Commercial Customers should be an “open position” procured through spot market
15 purchases.¹⁵ Subjecting Residential and Small Commercial Customers to spot market
16 purchases for 10 percent of their load – a *significant* portion of their SOS load – will not
17 provide stability in SOS supply prices.

18 ***d. A Managed Portfolio Approach will shift significant risks directly to National***
19 ***Grid and its SOS consumers, rather than simply reducing any perceived***
20 ***“risk premiums.”***

21 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT “BUYING**
22 **BLOCK PRODUCTS INSTEAD OF FULL REQUIREMENTS SERVICE**

¹⁴ RIDPUC-Hahn Direct at p.27 (lines 17-19).

¹⁵ RIDPUC-Hahn Direct at Exhibit RSH-8.

1 **CONTRACTS CAN HELP REDUCE THE RISK PREMIUMS CONTAINED IN THE**
2 **PRICE OF THOSE PRODUCTS”?**¹⁶

3 **A.** First, to be clear, what Mr. Hahn refers to as a ‘premium’ is better described as a
4 ‘monetization’ of risk. Wholesale suppliers bidding on a full requirements contract may
5 place a certain value on the risk that they assume, for instance, for customer migration. The
6 calculation for this monetization will depend on an individual wholesale supplier’s
7 perception of the level of such risk, its ability to manage the risk and its appetite for assuming
8 the risk. By removing the suppliers’ potential for monetization and management of this risk,
9 a Managed Portfolio Approach takes the actual risk and places it directly on consumers’
10 backs. In other words, it is a zero sum game. Customers bear the “cost” of migration either
11 in a monetized price or in the form of an assumed risk. This type of shifting of risks directly
12 to Residential and Small Commercial consumers fundamentally alters the nature of the SOS
13 product being provided by National Grid.

14 Altering the nature of the SOS product in this way is not consistent with the fundamentals
15 of retail competition. In accordance with the *Electric Utility Restructuring Act*
16 (“Restructuring Act”), SOS is to be provided by National Grid “to customers that have not
17 elected to enter into power supply arrangements with other nonregulated power suppliers.”¹⁷
18 In addition, National Grid explains that “Effective January 1, 2010, the provision of LRS will
19 terminate and all [Last Resort Service (“LRS”)] customers will be immediately transitioned

¹⁶ RIDPUC-Hahn Direct at p.27 (lines 15-17).

¹⁷ Rhode Island Gen. Laws § 39-1-27.3.

1 to SOS.”¹⁸ Under the Restructuring Act, LRS is to be provided by National Grid to
2 “customers who have left the standard offer for any reason and are not otherwise receiving
3 electric service from nonregulated power producers.”¹⁹ In this way, SOS will serve as the
4 only back-stop service for products offered by competitive retail suppliers.

5 As a back-stop service, SOS should be fashioned as a plain-vanilla, low-risk product. In
6 the spirit of retail competition, rather than forcing customers to assume certain risks as is the
7 case under a Managed Portfolio Approach, the Commission should allow customers to
8 choose to assume or manage risks for themselves. Those customers that place a low value on
9 price stability, for instance, can leave the low-risk, stable-priced SOS provided under full
10 requirements contracts, and instead choose a more volatile supply option from a competitive
11 retail suppliers.

12 **Q. BUT ISN'T THERE SOME VALUE IN PURCHASING MORE “BLOCK**
13 **PRODUCTS” AND OTHER STANDARD PRODUCTS IN THE MARKET**
14 **THROUGH A MANAGED PORTFOLIO APPROACH, RATHER THAN THROUGH**
15 **FULL REQUIREMENTS CONTRACTS BECAUSE OF THE NUMBER OF RISKS**
16 **AND, IN TURN, MONETIZATIONS THAT A SUPPLIER MUST CONSIDER WHEN**
17 **PRICING A FULL REQUIREMENTS PRODUCT?**

18 **A.** This question represents the false assumption that block products will avoid most of the risks
19 that are monetized in a full requirements product. In fact, block products include all of the
20 same risks – and, in turn, monetization of risks – as full requirements products for items
21 including, but not limited to, rising fuel costs, inflation, new energy taxes, market rule
22 changes, market price changes prior to bid acceptance, and changes in credit standing. It

¹⁸ (Revised) Direct Testimony of Jeanne A. Lloyd, Commission Docket No. 4041 (submitted Apr. 29, 2009) at p.5 (lines 14-16).

¹⁹ Rhode Island Gen. Laws § 39-1-27.3(c).

1 follows that the only risk that may not be priced into the costs for standard block products is
2 that of load variation, including, but not limited to, variation due to customer migration.
3 However, if the fixed costs for the added benefits of full requirements products – *including*
4 for management of load variation – are highly constrained through the competitive nature of
5 full requirements procurements, as is the case under the current Commission-approved FRS
6 Structure, then it follows that a Managed Portfolio Approach will not result in more
7 competitive prices than those achieved under the FRS Structure – a structure which has the
8 additional benefit of eliminating management risks.

9 *e. A FRS Structure is better equipped to work with and promote the goals of*
10 *retail competition.*

11 **Q. FINALLY, HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT**
12 **“LEAVING AN OPEN POSITION, THE PORTION OF THE PORTFOLIO**
13 **SUPPLIES BY SPOT MARKET PURCHASES, CAN EFFECTIVELY DEAL WITH**
14 **LOAD FLUCTUATIONS AND ANY MIGRATION OR SWITCHING THAT MIGHT**
15 **OCCUR”?**²⁰

16 **A.** As we explain above, the Managed Portfolio Approach is *not* as effective at managing “load
17 fluctuations and any migration or switching that might occur,” because it places all of the
18 risks of any such switching directly on the backs of Residential and Small Commercial
19 Customers through significant and inappropriate levels of spot market positions.

20 The FRS Structure is better able to manage and encourage appropriate retail market
21 developments, and will more fully meet the needs of competition than a Managed Portfolio
22 Approach. By utilizing fixed-price, full requirements supply contracts through a FRS
23 Structure, National Grid will insulate its customers from short-term *increases* in the costs of

²⁰ RIDPUC-Hahn Direct at p.27 (lines 17-19).

1 energy and take advantage of competitive wholesale markets by providing a competitively-
2 procured, fixed-price SOS supply. In a market where prices *decline* after a full requirements
3 procurement, customers will have the ability to take advantage of competitive retail markets
4 by shopping for lower-priced supply from a competitive retail supplier.

5 On the other hand, customers under a Managed Portfolio Approach who cannot or choose
6 not to shop may be subject to short-term run ups in costs in a particular month due to the
7 Managed Portfolio Approach’s “open positions” and reliance on spot market pricing.

8 Furthermore, as mentioned in Constellation’s Direct Testimony at pages 10 to 11, the
9 Managed Portfolio Approach also carries with it a significant risk that load fluctuation – e.g.,
10 due to customer attrition to competitive retail suppliers, weather-related effects on usage or
11 economy-related effects on customer load requirements – may *exceed* the designated “open
12 positions,” thereby leaving National Grid with an excess of generation supply under fixed-
13 quantity, Long Term Contracts. Such a situation, in turn, creates an incentive for a utility to
14 discourage customers from shopping or otherwise taking actions to reduce SOS load use
15 (e.g., through demand response or energy efficiency programs) in order to prevent a
16 “stranded cost.” This is one of the risks that Rhode Island sought to avoid by mandating
17 generation asset divestiture in connection with retail choice implementation.

18 **2. Mr. Hahn’s Statements to Address Constellation’s Positions Are Unsupported**
19 **and Fail to Diminish the Important Reasons to Adopt a FRS Structure.**

20 **Q. WHAT ARGUMENTS DOES MR. HAHN USE TO SUPPORT HIS**
21 **DISAGREEMENT WITH CONSTELLATION’S POSITION IN FAVOR OF A FRS**
22 **STRUCTURE TO SERVE THE SOS REQUIREMENTS OF NATIONAL GRID’S**
23 **CUSTOMERS?**

24 **A.** Mr. Hahn states, generally, that:

- 1 (a) Constellation “has a vested interest” in the FRS Structure, “has no inherent obligation to
2 serve customers or provide power at the lowest costs,” and “will sell power only when it
3 believes it can make a profit”;²¹
- 4 (b) Constellation “cannot claim that the issue [of a Managed Portfolio Approach] wasn’t
5 fully vetted”;²²
- 6 (c) It is not “inefficient for [National Grid] to maintain the resources necessary to
7 implement” a Managed Portfolio Approach;²³
- 8 (d) Constellation’s “vast resources” do not “make it better suited to determine what SOS
9 power will cost”;²⁴
- 10 (e) A “[M]anaged [P]ortfolio [A]pproach [will not] place excessive burdens on the
11 Commission”;²⁵
- 12 (f) A “[M]anaged [P]ortfolio [A]pproach [does not] require market timing”;²⁶
- 13 (g) A “[M]anaged [P]ortfolio [A]pproach [is] used in other jurisdictions”, including for
14 “National Grid Energy, and PPL”;²⁷
- 15 (h) “Full Requirements Service contracts [are not] more compatible with competitive
16 markets”;²⁸ and

²¹ RIDPUC-Hahn Direct at p.32 (lines 9-15).

²² RIDPUC-Hahn Direct at p.32 (lines 16-22).

²³ RIDPUC-Hahn Direct at p.33 (lines 1-6).

²⁴ RIDPUC-Hahn Direct at p.33 (lines 7-17).

²⁵ RIDPUC-Hahn Direct at pp.33 (line 18) – 34 (line 2).

²⁶ RIDPUC-Hahn Direct at p.34 (lines 3-7).

²⁷ RIDPUC-Hahn Direct at p.34 (lines 8-12).

²⁸ RIDPUC-Hahn Direct at p.34 (lines 13-18).

1 (i) National Grid’s “SOS load obligations [must not] always be met by Full Requirements
2 Service.”²⁹

3 **Q. HOW DO YOU RESPOND TO THIS REASONING?**

4 **A.** Again, Mr. Hahn’s statements above are just that – statements for which Mr. Hahn provides
5 little or no evidence for support, and which Mr. Hahn seems to ask the Commission to accept
6 as true despite the lack of evidentiary support. Once more, we will nevertheless respond and
7 provide explanations, based on Constellation’s experience, that each of Mr. Hahn’s
8 statements is incorrect or, at best, incomplete.

9 *a. Wholesale suppliers bidding on standard products under a Managed*
10 *Portfolio Approach will not be willing to supply them at a financial loss.*

11 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENTS THAT**
12 **CONSTELLATION “HAS A VESTED INTEREST” IN THE FRS STRUCTURE,**
13 **“HAS NO INHERENT OBLIGATION TO SERVE CUSTOMERS OR PROVIDE**
14 **POWER AT THE LOWEST COSTS,” AND “WILL SELL POWER ONLY WHEN IT**
15 **BELIEVES IT CAN MAKE A PROFIT”?**³⁰

16 **A.** First, it is true that Constellation has a “vested interest” in providing full requirements
17 products, as Constellation – like many wholesale suppliers active in wholesale markets in
18 New England and throughout the U.S. – has developed a high degree of expertise in
19 managing utility load; but that fact does not diminish the value of full requirements
20 products.³¹ Moreover, as a potential provider of each of the products that National Grid
21 would need to purchase under a Managed Portfolio Approach, Constellation would maintain
22 a “vested interest” in such procurements as well. We should note that we also understand

²⁹ RIDPUC-Hahn Direct at p.34 (lines 19-20).

³⁰ RIDPUC-Hahn Direct at p.32 (lines 9-15).

³¹ Left unsaid in Mr. Hahn’s testimony is whether he thinks it is more appropriate for a utility (under a Managed Portfolio Approach) to be guaranteed a profit on all of the energy it sells to ratepayers.

1 that Mr. Hahn may have a “vested interest” himself in the Managed Portfolio Approach, as
2 his firm has also provided portfolio management consulting services for several small
3 regulated electric providers in the past.³²

4 Next, it is inarguable that a wholesale supplier that wins the right to supply a portion of
5 National Grid’s SOS load in fact takes on a serious and strong contractual obligation to serve
6 such SOS load to National Grid for the benefit of its customers; these obligations are legally
7 enforceable, even if they are not statutory. Moreover, as we explain in more detail later in
8 our testimony, Constellation and other wholesale SOS suppliers possess a need, a duty *and*
9 an incentive to provide such SOS load at the lowest possible costs. Constellation has a *need*
10 to provide power at the lowest costs in order to actually *win* the obligation to supply National
11 Grid’s load under the highly competitive FRS Structure’s procurements; only the lowest cost
12 suppliers – for all requirements of FRS, including the load management function – become
13 winning bidders. Constellation has a *duty* and an *incentive* to supply SOS load at the lowest
14 costs in order to keep our business healthy – and yes, profitable – and able to meet SOS and
15 other supply obligations across the country, and in order to continue to be successful in
16 winning supply obligations in future utility load procurements. In this way, Mr. Hahn fails to

³² See, e.g., RIDPUC-Hahn Direct at p.1 (lines 12-14) (Mr. Hahn states that “In 2004, I joined La Capra Associates. Since then, I have worked on projects related to resource planning, transmission, [and] power procurement”); see also *Direct Testimony of Douglas C. Smith on Behalf of Green Mountain Power Corporation*, Vermont Public Service Board Docket No. 7176 (filed Apr. 14, 2006) at pp.1 (line 22) – 2 (line 3) (where La Capra employee, Douglas C. Smith, testifies that “Since joining La Capra Associates in 1991, I have . . . led the management of the electric power supplies of two Vermont electric utilities -- Washington Electric Cooperative and Vermont Electric Cooperative -- and have advised several other utilities in Vermont and New England regarding their power transactions and risk management strategies. I have also assisted several Vermont utilities in the development of integrated resource plans”).

1 recognize that a cost-minimization incentive goes hand in hand with business development
2 and success incentives; competition breeds a drive for innovation and efficiencies.

3 On the other hand, a utility such as National Grid under a Managed Portfolio Approach
4 has little economic incentive or duty to minimize costs, as it operates under an incentive to
5 minimize regulatory risks. All of the utility's costs plus a *guaranteed* profit – which are not
6 constrained by competitive forces – are passed through to customers. Said another way,
7 under a Managed Portfolio Approach, the utility has no economic incentive to produce an
8 optimal least-cost portfolio through innovation and efficiencies.

9 **Q. IS THERE ANY ADDITIONAL RECENT EVIDENCE AVAILABLE FOR THE**
10 **COMMISSION'S REVIEW THAT SUPPORTS YOUR CONCLUSIONS**
11 **REGARDING THE EFFICIENCIES ACHIEVED BY RELIANCE ON COMPETITIVE**
12 **BIDS FOR FRS BY FIRMS SUCH AS CONSTELLATION?**

13 **A.** Yes. The Analysis Group Study we mentioned earlier and that we have attached to this
14 testimony concludes that utilities should support a competitive market for load
15 procurement.³³ The Study specifically promotes the use of competitive procurements for
16 FRS products to meet utilities' load supply obligations, laying out characteristics that aptly
17 describe the very FRS Structure that is before the Commission in the instant proceeding.³⁴
18 According to the Study, through this FRS Structure, National Grid “can make good use of

³³ Analysis Group Study (already short-cited at fn 9) at p.i (concluding that “policy makers should stay the course and support the development of competitive markets”).

³⁴ See Analysis Group Study at pp.10-11 (stating that “it is possible to design and implement competitive procurement processes so as to hedge risk . . . through staggered procurements . . . for different future time periods”)

1 competitive markets to find lowest-cost suppliers of ‘full requirements’ power to meet the
2 needs of [SOS] customers”³⁵ The Analysis Group Study points out that:

3 One of the advantages of competition in the procurement of such [FRS
4 products] is that it taps into the abilities and skills of different players to
5 develop different and innovative strategies to meet and adapt to power supply
6 conditions as they change in the future . . . [and] passes risk from consumers
7 and the utility that is serving as their supply conduit over to the third party
8 suppliers.³⁶

9 **Q. IS THE FRS STRUCTURE FOR NATIONAL GRID APPROPRIATELY**
10 **STRUCTURED SO AS TO TAKE ADVANTAGE OF THESE EFFICIENCIES?**

11 **A.** Yes. As we have described above, the FRS Structure rightly relies on the use of competitive
12 procurements to obtain all of the energy and related services (including load management
13 services) required to meet National Grid’s SOS obligations. In fact, a recent study submitted
14 by the National Association of Regulatory Utility Commissioners (“NARUC”) to the Federal
15 Energy Regulatory Commission (“FERC”) as part of the NARUC/FERC Competitive
16 Procurement Collaborative found that:

17 [c]ompetitive procurements can provide utilities with a way of obtaining
18 electricity supply that has the ‘best’ fit to customers’ needs at the ‘best’
19 possible terms . . . competitive procurements accomplish this goal by
20 requiring market participants to compete for the opportunity to provide
21 these services.³⁷

³⁵ Analysis Group Study at p.11.

³⁶ Analysis Group Study at p.11.

³⁷ *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*, the Analysis Group, Dr. Susan F. Tierney and Dr. Todd Schatzki, Commissioned by NARUC (issued July 2008) (<http://www.naruc.org/Publications/NARUC%20Competitive%20Procurement%20Final.pdf>) (“NARUC Procurement Study”) at p.i. A copy of the NARUC Procurement Study is attached hereto as Constellation Exhibit 2.3.

1 When properly structured to allow for a broad potential pool of bidders, the competitive FRS
2 Structure allows National Grid to obtain competitively-priced, favorable generation supply
3 contracts which include competitive prices for managing National Grid’s load supply.

4 **Q. DOES THE FRS STRUCTURE ENCOURAGE COMPETITION?**

5 **A.** Yes. The FRS Structure promotes a competitive market through use of a competitive
6 procurement process for wholesale supply. The Commission’s and RIDPUC’s roles in the
7 FRS Structure will result in a process that will be implemented in a non-discriminatory and
8 highly transparent manner. The FRS Structure benefits from a nondiscriminatory process in
9 which bidders generally are allocated appropriate risks as wholesale suppliers and are
10 provided sufficient information to tailor their bids specifically to the requirements of
11 National Grid’s load, and therefore provide the most competitive wholesale prices for the
12 benefit of National Grid’s customers.

13 National Grid has designed the FRS Structure such that winning bidders are able to be
14 determined on the basis of “least cost” alone, eliminating the need to make determinations
15 regarding bids based on other less objective criteria. As the NARUC Procurement Study
16 explains:

17 procuring products that meet standardized specifications . . . greatly
18 simplifies the evaluation process by allowing for the selection of winning
19 offers based on price terms alone. Identifying evaluation criteria that
20 reflect the attributes of greatest importance will increase the likelihood of
21 eliciting offers that best suit retail customers’ supply needs.³⁸

³⁸ NARUC Procurement Study at p.8.

1 **Q. BUT WHAT ABOUT MR. HAHN’S IMPLICATION THAT A “PROFIT” WILL BE**
2 **ADDED INTO ANY SUPPLY CONTRACT BID ON BY A SUPPLIER SUCH AS**
3 **CONSTELLATION UNDER THE FRS STRUCTURE?**

4 **A.** Mr. Hahn seems to suggest that a profit is added into a full requirements bid that otherwise is
5 avoided under a Managed Portfolio Approach’s procurements for other “standard” products.

6 In reality, any product that is purchased in the wholesale markets – whether a full
7 requirements product, a fixed short- or long-term block product, or a spot market purchase –
8 will include in its price some level of profit that the supplier is willing and able to receive.

9 Basic economic principles suggest that this is the case. When a seller sells a product –

10 whether he is selling oranges, widgets or electricity – he seeks a return on his costs of

11 producing the product. Basic economic principles also suggest that the price that a seller is

12 “willing” to sell his product for will be constrained by the price he is “able” to sell his

13 product for, so that in a competitive procurement, where only the lowest price from a pool of

14 sellers is accepted, each seller will have an incentive to drive down the price at which he is

15 “willing” to sell his product. This competitively constrained price for a full requirements

16 product, however, will include a seller’s perceived monetizations of risk (as we described

17 earlier in this testimony) as well as a profit on the overall full requirements product.

18 Depending on a supplier’s perception of the level of risks, its ability to manage risks and its

19 appetite for assuming risks, a supplier may have an ability to drive down further its

20 underlying costs and overall prices for an “all-in” FRS product. This especially is true for

21 suppliers that are able to spread their costs across a large portfolio of supply obligations – if a

22 supplier like Constellation experiences lower revenue or a loss due to one of its obligations,

23 for example, it is able to offset it against earnings across its entire portfolio of obligations. A

1 single utility under a Managed Portfolio Approach will have neither the competitive
2 incentives to drive down its costs, nor the ability to hedge its obligations and costs across a
3 broad, multi-regional portfolio.

4 ***b. Constellation does not argue in this proceeding that the Commission should***
5 ***not “consider” a Managed Portfolio Approach – only that, upon***
6 ***consideration, it is clear that a FRS Structure is best to meet SOS consumers’***
7 ***needs.***

8 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENTS THAT**
9 **CONSTELLATION “CANNOT CLAIM THAT THE ISSUE [OF A MANAGED**
10 **PORTFOLIO APPROACH] WASN’T FULLY VETTED” AND THAT THE**
11 **COMMISSION SHOULD NOT CONSIDER A MANAGED PORTFOLIO**
12 **APPROACH?³⁹**

13 **A.** First, it appears that Mr. Hahn has confused two sections of Constellation’s Direct
14 Testimony. Whereas Mr. Daniels *did* state that the Commission should not consider the issue
15 of Long Term Contracts for renewable resources as part of this proceeding (as we still must
16 await additional guidance from Commission Docket No. 4069), he *did not* make statements
17 as to whether the Commission should not reaffirm the Commission’s support of the FRS
18 Structure as proposed by National Grid. Indeed, we encourage the Commission to consider
19 the various approaches proposed in this proceeding, including the additional evidence we
20 present herein that lends support to the FRS Structure. With respect to the issue of
21 procurement structure, Constellation maintains its position in this proceeding that the FRS
22 Structure is likely to produce better results for and is better designed to meet the needs of
23 National Grid’s SOS customers.

³⁹ RIDPUC-Hahn Direct at p.32 (lines 16-22).

1 **Q. HOW IS THE FRS STRUCTURE LIKELY TO PRODUCE BETTER RESULTS**
2 **THAN MR. HAHN’S MANAGED PORTFOLIO APPROACH FOR NATIONAL**
3 **GRID’S SOS CUSTOMERS?**

4 **A.** National Grid’s FRS Structure is likely to assure better results than Mr. Hahn’s Managed
5 Portfolio Approach for SOS customers because: (1) the FRS Structure appropriately shifts
6 most risks to wholesale suppliers, who are best equipped to assume and manage such risks;
7 and (2) the costs for having wholesale suppliers bear such risks will be highly constrained
8 through competition and the incentives for suppliers to drive down costs of managing SOS
9 load.

10 **Q. CAN YOU PLEASE EXPLAIN IN ADDITIONAL DETAIL THE BENEFITS OF**
11 **SHIFTING RISKS TO WHOLESALE SUPPLIERS?**

12 **A.** Of course. As risks and costs to National Grid appropriately are passed on to its customers, it
13 follows that the FRS Structure “limits the risk” to National Grid’s customers by shifting them
14 largely to full requirements suppliers. In addition, full requirements contracts provide
15 consumers with price insurance for the duration of the contract by shifting price risk to
16 wholesale suppliers. For instance, Mr. Hahn has in testimony elsewhere pointed to
17 Wellsboro Electric Company (“Wellsboro”) as *an example* of a utility using a Managed
18 Portfolio Approach. In fact, Wellsboro is instead an excellent example of the benefits of
19 shifting price risk to the supplier via a FRS Structure.

20 **Q. HOW DOES WELLSBORO SERVE AS AN EXAMPLE THAT SUPPORTS**
21 **STAYING WITH A FRS STRUCTURE, INSTEAD?**

22 **A.** Wellsboro is a relatively small Pennsylvania utility procuring its equivalent of SOS
23 requirements through a Managed Portfolio Approach, and faced a market “surprise” that
24 forced it in 2008 to seek permission from the Pennsylvania Public Utility Commission

1 (“Pennsylvania PUC”) to recover in excess of \$2-million in additional congestion costs from
2 its customers because of an unexpected congestion event.⁴⁰ Wellsboro’s customers did not
3 have “insurance” provided by a FRS Structure for such an event and, as a result, had to bear
4 the burden themselves for the surprise rise in costs, as the Pennsylvania PUC approved the
5 pass through of such costs.⁴¹

6 If this Commission or anyone else was to attempt to compare Wellsboro to another
7 similarly situated utility that employs a FRS Structure, how could the evaluator account for
8 events that *do not occur*, in comparing the two methods? As we have explained, FR Products
9 and block products are inherently different in nature, especially due to the “insurance”
10 provided by a supplier through a FRS Structure. The fact that wholesale prices *did not*
11 actually spike or drop in a particular year does not mean that it was not valuable to have
12 protection in place against that risk. If we don’t get sick in a year, we don’t look back and
13 say “we shouldn’t have bought health insurance last year; that was a bad decision.”⁴²

14 As also documented in Constellation’s Direct Testimony and herein, the FRS Structure
15 provides a proper balance between obtaining the most competitive prices for consumers and
16 maintaining a reasonable level of price stability by providing a fixed price product, while
17 appropriately placing risks such as volume risk and virtually all price risks on wholesale
18 suppliers.

⁴⁰ See *Joint Statement of Commissioner Kim Pizzigrilli and Vice Chairman James H. Cawley*, Commission Docket No. P-2008-202057 (issued Feb. 28, 2008) (“Wellsboro Feb. 2008 Decision”) at p.1.

⁴¹ See Wellsboro Feb. 2008 Decision at p.1.

⁴² See *Rebuttal Testimony of Michael M. Schnitzer, Director, The NorthBridge Group, Inc., on Behalf of Intervenors Constellation Energy Commodities Group, Inc. and Constellation NewEnergy, Inc.*, Pennsylvania PUC Docket No. P-00072342 (filed Mar. 11, 2008) at pp.15 (line 20) – 16 (line 2).

1 ***c. Mr. Hahn makes contradictory statements indicating that National Grid has***
2 ***not exhibited the proper skills to effectively manage a portfolio under a***
3 ***Managed Portfolio Approach.***

4 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT IT IS NOT**
5 **“INEFFICIENT FOR [NATIONAL GRID] TO MAINTAIN THE RESOURCES**
6 **NECESSARY TO IMPLEMENT” A MANAGED PORTFOLIO APPROACH?⁴³**

7 **A.** Mr. Hahn lauds National Grid and states, “In the course of implementing its accelerated
8 procurement plan and in its filings to date, [National Grid] has already demonstrated that it
9 has the ability to effectively manage a true portfolio of power supplies.”⁴⁴ On the other hand,
10 Mr. Hahn has also been *critical* of National Grid’s decision to procure NYMEX financial
11 hedges in managing its power supplies.⁴⁵ Which one is it? Has National Grid made the right
12 or the wrong decisions with respect to its management of power supplies? If the answer is,
13 “Both!” or even, “A little of both!” then the evidence does not bode well for Mr. Hahn’s
14 Managed Portfolio Approach, because under his proposed design, as illustrated by
15 Wellsboro’s predicament, even *one* poor decision on the part of National Grid under a
16 Managed Portfolio Approach – whether for a “relatively simple portfolio” as purportedly
17 proposed by Mr. Hahn or a more complicated design – can have a material and detrimental
18 effect on consumers’ SOS prices. On the other hand, a poor decision by a wholesale FRS
19 supplier in managing its portfolio to supply a portion of SOS will have *no effect* on the prices
20 paid by SOS consumers, because the wholesale FRS supplier is contractually *obligated* to

⁴³ RIDPUC-Hahn Direct at p.33 (lines 1-6).

⁴⁴ RIDPUC-Hahn Direct at p.28 (lines 1-3).

⁴⁵ See RIDPUC-Hahn Direct at Exhibit RSH-4, p.3 (Mr. Hahn’s memorandum states, “We disagree [with National Grid] that [settling the NYMEX hedges against actual prices in the Accelerated Procurement Plan] would remove the hedge benefit from FRS contracts.” Mr. Hahn believes that “settling against actual prices . . . could yield lower prices to SOS customers.”).

1 provide its SOS share at a *fixed price* – the SOS consumer bears no risk for a FRS supplier’s
2 mismanagement. Why force SOS consumers to bear such risks, moreover, when National
3 Grid does not possess the level of expertise developed over time by wholesale suppliers such
4 as Constellation, and when such suppliers bid to provide such fixed price contracts at the
5 lowest competitive price?

6 **Q. BUT ISN’T IT TRUE THAT NATIONAL GRID CAN DEVELOP EXPERTISE**
7 **SIMILAR TO THAT OF WHOLESALE FRS SUPPLIERS IN ORDER TO ASSUME**
8 **AND MANAGE THE RISKS OF ITS OWN LOAD OBLIGATIONS?**

9 **A.** Requiring National Grid to duplicate what is already in place at Constellation and at other
10 FRS suppliers (*i.e.*, retain personnel or hire outside consultants, expend resources to manage
11 an energy portfolio, determine when to make shorter and longer term purchases, etc.) is an
12 inefficient way to attempt to achieve competitive and lowest cost SOS prices for consumers.
13 As National Grid’s load must always be met with full requirements products (regardless of
14 the type of procurement process the Commission adopts), in order to actively manage its load
15 obligations, National Grid (or its consultants) would at a minimum have to retain individual
16 experts who understand and follow not only electric energy and other commodity markets,
17 but also ancillary services, capacity, renewable product and other markets. Doing so would
18 be an inefficient allocation of resources, especially when considering the risks that would be
19 shifted to and shouldered by National Grid and its SOS customers.

1 *d. Wholesale suppliers’ drive for efficiencies and cost reductions will be*
2 *reflected in bids for SOS supply, passing the savings achieved onto customers*
3 *through the FRS Structure’s competitive procurements.*

4 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT**
5 **CONSTELLATION’S “VAST RESOURCES” DO NOT “MAKE IT BETTER**
6 **SUITED TO DETERMINE WHAT SOS POWER WILL COST”?**⁴⁶

7 **A.** Mr. Hahn claims to propose a “relatively simple” Managed Portfolio Approach, but fails to
8 explain how this will be least cost.⁴⁷ The only way to optimize a portfolio is to create the
9 proper incentives that will encourage portfolio managers – whether they be the FRS suppliers
10 under the FRS Structure or National Grid under a Managed Portfolio Approach – to serve
11 load at the lowest cost. Under Mr. Hahn’s proposed Managed Portfolio Approach, the
12 Commission has no way to know whether the costs of National Grid’s supply portfolio have
13 been minimized or only “simplified” through basic products and limited management.

14 On the other hand, under the FRS Structure, by bidding out FRS obligations, there exists
15 a basis to compare and take the lowest offer; the Commission has certainty that National Grid
16 has met its SOS obligations, including load management, at the lowest cost. A diverse pool
17 of potential wholesale suppliers – rather than sole-sourced independent consultants or
18 utilities themselves – provides the most cost-effective method of SOS supply management
19 for utility load.

⁴⁶ RIDPUC-Hahn Direct at p.33 (lines 7-17).

⁴⁷ RIDPUC-Hahn Direct at p.33 (lines 14-17).

1 **Q. BUT HOW WILL CONSTELLATION’S OR ANOTHER WHOLESALE SOS**
2 **SUPPLIER’S “VAST RESOURCES” PROVIDE LOW COST SUPPLY**
3 **MANAGEMENT FOR NATIONAL GRID’S PARTICULAR SOS LOAD PROFILE?**
4 **DOESN’T NATIONAL GRID HAVE BETTER ACCESS TO ITS CUSTOMERS’**
5 **LOAD USAGE AND HISTORY, AND WON’T THIS MAKE NATIONAL GRID**
6 **BETTER SUITED TO MEET THAT LOAD PROFILE?**

7 **A.** Under full requirements procurements, utilities such as National Grid provide to potential
8 bidders prior to procurements, and to winning bidders on an ongoing basis afterwards, *all of*
9 *the necessary load data* for National Grid’s individual customer classes. Wholesale suppliers
10 are specialists in the area of portfolio management, and with their “vast resources,” expertise
11 and ability, they can appropriately utilize this data to manage portfolios of supply at the least
12 possible cost, by allocating the costs for their operations over much larger load obligations
13 throughout the country. Moreover, such suppliers are able to draw from their substantial
14 experience throughout New England and in other jurisdictions to develop proprietary models
15 of customer behavior and switching patterns, to refine these models, and to better analyze the
16 local data provided by National Grid. These wholesale suppliers will pass on the efficiencies
17 they achieve due to their advanced risk management skills and experience in the form of
18 more competitive bids for full requirements SOS products in the FRS Structure’s
19 procurements. Wholesale suppliers have already invested in, and continue to make
20 significant investment in acquiring, experts in each specific type of market which makes up
21 full requirements SOS supply. Whereas Mr. Hahn suggests that National Grid can “create a
22 relatively simple portfolio of a prudent mix of standard electric products,”⁴⁸ in fact, it is
23 wholesale suppliers’ expertise which makes a wholesale supplier better equipped than

⁴⁸ RIDPUC-Hahn Direct at p.33 (lines 14-17).

1 National Grid to both (1) determine what is a “prudent mix” of products to employ in order
2 to serve a utility’s SOS load at the lowest, fixed cost to SOS consumers, and (2) manage load
3 variation that inevitably will affect any supply portfolio – even one that is intended to be
4 “relatively simple.” In sum, wholesale suppliers are better equipped to perform these
5 functions, and their costs are driven down through competition.

6 *e. Mr. Hahn fails to address the regulatory reviews that may be required under*
7 *a Managed Portfolio Approach – but not the FRS Structure – in order to*
8 *ensure, even after-the-fact, that National Grid has prudently managed its*
9 *portfolio.*

10 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT A “[M]ANAGED**
11 **[P]ORTFOLIO [A]PPROACH [WILL NOT] PLACE EXCESSIVE BURDENS ON**
12 **THE COMMISSION”?**⁴⁹

13 **A.** Mr. Hahn ignores entirely the increased need for regulatory oversight and management that is
14 commensurate with his proposed Managed Portfolio Approach, and which is highlighted in
15 Constellation’s Direct Testimony. As discussed therein, the Commission has an obligation to
16 ensure that National Grid has acted prudently in procuring its SOS obligations and, under a
17 Managed Portfolio Approach, this duty requires that the Commission conduct an after-the-
18 fact review to determine the prudence of National Grid’s various management activities,
19 especially with respect to National Grid’s planning for future load variation (and, in turn,
20 decisions with respect to the amounts of various “standard” products that must be purchased)
21 and National Grid’s decisions on timing (e.g., delays/accelerations) for procuring such
22 products, as we explore in more detail in Section III.2.f. below. Under a FRS Structure, on
23 the other hand, National Grid will have acted prudently by basing procurement decisions

⁴⁹ RIDPUC-Hahn Direct at pp.33 (line 18) – 34 (line 2).

1 solely on choosing the lowest-cost suppliers, as National Grid will not have to make
2 decisions to vary the type, size or timing of product purchases after Commission approval of
3 such FRS Structure and plan.

4 **Q. IN ADDITION TO THE BURDEN PLACED ON THE COMMISSION UNDER**
5 **THESE AFTER-THE-FACT REVIEWS, WILL THESE REVIEWS PLACE**
6 **BURDENS ON CONSUMERS?**

7 **A.** Yes. The need for these after-the-fact reviews and the chance that the Commission may deny
8 National Grid cost recovery on the basis that it did not act prudently in managing its portfolio
9 can only lead to higher, rather than lower, costs for SOS consumers. As explained in
10 Constellation's Direct Testimony, because a utility under a Managed Portfolio Approach may
11 face a risk of after-the-fact disallowances of certain portfolio costs on the grounds of
12 imprudence, such a utility may be reluctant to develop and take advantage of more
13 complicated risk management and hedging strategies that could have lowered costs for
14 managing and providing SOS. In addition, under a Managed Portfolio Approach, National
15 Grid's lenders and suppliers, due to creditworthiness concerns based on the potential for
16 after-the-fact disallowances, may be more likely to charge premiums to the utility (and, in
17 turn, its SOS customers) for the extension of credit and sales of individual energy/energy-
18 related products, respectively.

1 ***f. Mr. Hahn ignores his own statements indicating that his Managed Portfolio***
2 ***Approach will in fact require National Grid and/or the Commission to***
3 ***engage in market timing.***

4 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT A “[M]ANAGED**
5 **[P]ORTFOLIO [A]PPROACH [DOES NOT] REQUIRE MARKET TIMING”?**⁵⁰

6 **A.** Frankly, we think Mr. Hahn ignores his own statements and proposal in making such an
7 unsupported statement. Mr. Hahn explicitly proposes that, as part of his Managed Portfolio
8 Approach:

9 For each transaction contemplated in this plan, I have provided a window
10 of time within which the Company should monitor market conditions and
11 consummate purchases if conditions are favorable.⁵¹

12 He reiterates this notion in his attached “Procurement Schedule & Plan” at Exhibit RSH-8 of
13 his testimony, stating that National Grid “should monitor market conditions between these
14 dates, and schedule procurements based upon markets conditions and time.”⁵²

15 **Q. WHY DO YOU OPPOSE THE NOTION OF NATIONAL GRID ENGAGING IN**
16 **SUCH MARKET-TIMING?**

17 **A.** Under a market-timing approach, which is both inherent to and explicit in Mr. Hahn’s
18 Managed Portfolio Approach, National Grid would have the discretion to enter into contracts
19 for various SOS supply products at various times, depending on when it perceives market
20 conditions to be favorable. There are two fundamental flaws with a utility using a market
21 timing approach to procurement. First, there is no reason to believe that a utility, the
22 Commission or a consultant acting on the utility’s behalf can outguess the market, which is
23 what market timing is premised upon. Second, a market timing approach – where a utility

⁵⁰ RIDPUC-Hahn Direct at p.34 (lines 3-7).

⁵¹ RIDPUC-Hahn Direct at p.29 (lines 5-8).

⁵² RIDPUC-Hahn Direct at Exhibit RSH-8, at FN.

1 must use its “judgment to determine” when to make purchases – creates regulatory review
2 and prudence issues that are not present in the FRS Structure, as discussed above.

3 **Q. WHY DO YOU SAY THAT MARKET TIMING IS PREMISED UPON THE**
4 **ABILITY TO OUTGUESS THE MARKET?**

5 **A.** Under the FRS Structure, National Grid will buy FRS products on a periodic staggered basis.

6 Each time National Grid accesses the market, we would expect that the offers it receives
7 from prospective suppliers would be based on then-prevailing forward price curves for
8 underlying products. Proponents of market timing are, in effect, proposing that a utility
9 should look at forward prices at a given moment in time and make a decision about whether
10 to procure supply at that time based on the utility’s view as to whether forward prices are
11 going to move up or down from that level in the future. Under this approach, if the utility
12 “perceives” that forward prices are going to move up, it should lock in supply at that time. If
13 the utility “perceives” that forward prices are going to move down, it should wait.

14 The obvious problem with this logic is that the utility has no way of knowing how
15 forward prices will move. It may “perceive” that forward prices are going to move down,
16 and postpone procurement, and find that prices in fact rise. Conversely, it may lock in at
17 what it perceives is a good price, only to find after the fact that it has bought at the top of the
18 market. The movement of future market prices is inherently uncertain, and there is no reason
19 to believe that a utility can outperform a procurement process that relies on a predetermined,
20 periodic schedule for purchases. Moreover, under a Managed Portfolio Approach the issue is
21 exacerbated because there is no reason to believe that National Grid would be able to have

1 sufficient knowledge to engage in “market-timing” for each of the markets in which each of
2 the components of SOS supply must be procured.

3 A utility is never likely to be in a position to outguess wholesale energy and energy-
4 related markets, nor should it try. The better approach is to avoid market timing and buy
5 periodically for FRS products, as proposed in the FRS Structure.

6 **Q. CAN YOU PROVIDE ANY ADDITIONAL DETAIL REGARDING THE PRUDENCE**
7 **ISSUES ASSOCIATED WITH MARKET TIMING?**

8 **A.** Yes. The market timing approach recommended by Mr. Hahn creates regulatory review and
9 prudence disallowance issues, as mentioned in the previous Section III.2.e. If a utility has
10 discretion to make purchases based on its view of when there is a market “low,” what
11 happens after the fact if it is wrong, and forward prices drop at some point after it bought? If
12 the contracts can be disallowed after the fact because it is later learned that the utility guessed
13 wrong on the timing of its purchases, this could raise serious financial issues for the utility.
14 This in turn raises the possibility that suppliers will add a risk premium for default risk, or
15 require costly credit facilities to protect themselves. To avoid this, most advocates of market
16 timing approaches propose that state commissions set up a process for a rapid, “real time”
17 pre-approval when a utility decides to access the market. While these regulatory pre-
18 approval approaches may reduce the ex-post disallowance risk, they can be cumbersome to
19 administer. Moreover fundamentally, prudence pre-approval of the timing of when to access
20 the market rests on the premise that the regulators are themselves in a position to evaluate the
21 utility’s market timing decisions – to say “yes, we agree the forward market is going to go
22 up, so it is prudent to buy some supply now” or “no, we think you should wait because

1 market conditions are going to become more favorable later.” Just as there is no reason why
2 a utility would have an inherent advantage in figuring out how to time the market (*i.e.*, when
3 to buy “opportunistically”), relative to a process that relies on a fixed procurement schedule,
4 there is no reason that a regulator would have such an advantage.

5 *g. RIDPUC witness Hahn fails to include the important fact that FRS*
6 *Structures are used to procure SOS requirements for large utilities across*
7 *the eastern seaboard, including in Pennsylvania for PECO Energy and PPL*
8 *Electric.*

9 **Q. HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT A “[M]ANAGED**
10 **[P]ORTFOLIO [A]PPROACH [IS] USED IN OTHER JURISDICTIONS”,**
11 **INCLUDING FOR “NATIONAL GRID ENERGY, AND PPL”?**⁵³

12 **A.** In that portion of Mr. Hahn’s testimony, he identifies as examples of entities using a
13 Managed Portfolio Approach: (1) two small Pennsylvania utilities, Citizens Electric
14 Company (“Citizens”) and Wellsboro (whose experience we discussed earlier), who between
15 them have only a bit more than 12,000 total customers;⁵⁴ (2) the municipally-owned electric
16 companies of Massachusetts; and (3) PECO Energy Company (“PECO Energy”) and PPL
17 Electric Utilities Corporation (“PPL Electric”), two of the larger utilities in Pennsylvania.

18 Mr. Hahn fails to mention, however, that with respect to PECO Energy and PPL Electric,
19 a so-called “Managed Portfolio Approach” will be used for only a very small portion of such
20 utilities’ Residential load. In the case of PECO Energy, in reaching a settlement on its
21 procurement plan for Default Service (Pennsylvania’s SOS equivalent), the utility agreed to
22 supply only a load-following 25 percent of its Residential load requirements through a

⁵³ RIDPUC-Hahn Direct at p.34 (lines 8-12).

⁵⁴ See Citizens and Wellsboro websites at <http://www.wellsboroelectric.com/weco/companyAboutUs.asp> and <http://www.citizenselectric.com/index.asp>

1 structured “block and spot” approach for the period beginning on January 1, 2011; the
2 remaining 75 percent of PECO Energy’s Residential load will be served using a FRS
3 Structure.⁵⁵ In addition, Mr. Hahn neglects the fact that PECO Energy’s Small Commercial,
4 Medium Commercial and Large Commercial & Industrial classes will *all* be served through
5 FRS Structures.⁵⁶

6 Next, with respect to PPL Electric, in reaching a settlement on its procurement plan for
7 Default Service, the utility agreed to supply only roughly 20 percent of its Residential load
8 requirements by procuring block products for the period beginning on January 1, 2011. This
9 structure, however, does not represent a “Managed Portfolio Approach” akin to that proposed
10 herein by Mr. Hahn, as these block products will serve only a portion of PPL Electric’s base
11 load, essentially, while the remaining 80 percent (approximately) of PPL Electric’s
12 Residential load will be served using a FRS Structure which includes limited spot market
13 purchases.⁵⁷ In addition, Mr. Hahn neglects the fact that PPL Electric’s Small Commercial &
14 Industrial and Large Commercial & Industrial classes will *all* be served through FRS
15 Structures including spot market purchases or through spot market purchases only (as is
16 common for large customer load in competitive markets throughout the country).⁵⁸

⁵⁵ See, generally, *Joint Petition for Settlement*, Pennsylvania PUC Docket No. P-2008-2062739 (filed Mar. 10, 2009) (“PECO Settlement”).

⁵⁶ See, generally, PECO Settlement.

⁵⁷ See, generally, *Joint Petition for Settlement*, Pennsylvania PUC Docket No. P-2008-2060309 (filed Mar. 11, 2009) (“PPL Electric Settlement”).

⁵⁸ See, generally, PPL Electric Settlement.

1 Mr. Hahn also ignores completely the fact that each of these utilities expressed positions
2 in litigation *against* a Managed Portfolio Approach and *in favor of* FRS Structures.⁵⁹ Finally,
3 Mr. Hahn has not pointed out that, though the Pennsylvania PUC approved these settlement
4 agreements for Default Service procurement for both PPL Electric and PECO Energy, when
5 the Pennsylvania PUC most recently had to issue a decision on the fully litigated issue of a
6 FRS Structure versus a Managed Portfolio Approach for two of that state's other larger
7 utilities (rather than simply a decision approving a settlement reached by parties), the
8 Pennsylvania PUC ruled each time in favor of a FRS Structure. Indeed, in ruling in favor of
9 a FRS Structure over a Managed Portfolio Approach for the Pennsylvania Power Company's
10 Residential Default Service supply, then-Chairman Wendell F. Holland stated:

11 The full requirements, load following staggered contract method provides
12 a more traditional approach This method provides for more stable
13 rates to residential customers. In addition, this method places most of the
14 price risk on suppliers rather than ratepayers⁶⁰

15 Then-Vice Chairman James H. Cawley added:

16 It is [a] lack of accountability that concerns me [regarding a Managed
17 Portfolio Approach]. At least in a [FRS Structure] there should be fewer
18 surprises – consumers will get the prices that were bid and won, and
19 wholesale suppliers will bear the cost of any failures on their part to
20 manage their portfolio of supplies. This accountability can be lost with a
21 simple pass through of costs, unless a more clear case can be made that
22 risks have been sufficiently managed or current and viable competitive
23 supply alternatives exist.⁶¹

⁵⁹ See, generally, *Petition of PECO Energy Company for Approval of its Default Service Program and Rate Mitigation Plan*, Pennsylvania PUC Docket No. P-2008-2062739 (Sept. 10, 2008); see also *Petition of PPL Electric Utilities Corporation for Approval of a Default Service Program and Procurement Plan*, Pennsylvania PUC Docket No. P-2008-2060309 (filed Aug. 28, 2008).

⁶⁰ *Statement of Chairman Wendell F. Holland*, Pennsylvania PUC Docket No. P-00072305 (issued Mar. 13, 2008).

⁶¹ *Statement of Vice Chairman Cawley*, Pennsylvania PUC Docket No. P-00072305 (issued Mar. 13, 2008).

1 Similarly, in a case in which Mr. Hahn also testified in support of a Managed Portfolio
2 Approach, the Pennsylvania PUC made a decision in favor of a FRS Structure for West Penn
3 Power d/b/a Allegheny Power Company. The Pennsylvania PUC ruled that:

4 The [Office of Consumer Advocate (“OCA”)] alleges that risk premiums .
5 . . will be included in full-requirements contracts making them less
6 economically efficient than its proposed [Managed Portfolio Approach].
7 However, the OCA has not proven, with numerical evidence, the
8 magnitude of such risk premiums or profits. Furthermore, no Party to this
9 proceeding is in the position to prove empirically that the flexibility
10 inherent in a managed portfolio will guarantee lower retail rates for
11 customers. While the price that a supplier may bid into a full-requirements
12 procurement will include some compensation for the cost and risk
13 associated with providing the service, suppliers are still motivated to price
14 bids competitively in order to win the procurement. The OCA was unable
15 to quantify either the risk premium or profit margins included in a full
16 requirements contract because it is impossible to accurately predict those
17 amounts. Furthermore, the OCA did not quantify the costs that a utility
18 will pay for managing its own portfolio or contracting out the task to a
19 consultant.⁶²

20 **Q. WHICH PROCUREMENT APPROACH HAS BEEN FAVORED BY LARGER**
21 **UTILITIES IN NEW ENGLAND?**

22 **A.** With the exception of two utilities in Vermont and New Hampshire, all of the larger utilities
23 in New England currently rely on some form of FRS Structure.

24 ***h. The FRS Structure is more compatible with competitive markets – both***
25 ***wholesale and retail – than Mr. Hahn’s Managed Portfolio Approach.***

26 **Q. DO YOU AGREE WITH MR. HAHN’S STATEMENT THAT “FULL**
27 **REQUIREMENTS SERVICE CONTRACTS [ARE NOT] MORE COMPATIBLE**
28 **WITH COMPETITIVE MARKETS”?**⁶³

29 **A.** No. First, with respect to wholesale competition, the FRS Structure will promote robust
30 levels of participation due to its well-designed, stable and non-discriminatory procurement

⁶² *Opinion and Order*, Pennsylvania PUC Docket No. P-00072342 (issued July 17, 2008).

⁶³ RIDPUC-Hahn Direct at p.34 (lines 13-18).

1 process. Moreover, due to potential bidders' interests in the well-defined full requirements
2 products and amounts, bidders will be comfortable with pricing such products through the
3 FRS Structure's procurements. For instance, one of the attractive aspects of the FRS
4 Structure is that the volume of load and size of contracts bid out by National Grid will be
5 sizable enough to warrant wholesale suppliers' putting their time and resources into
6 preparing bids for the procurements. Moreover, bidders in FRS procurements are selling not
7 only energy products but, significantly, their expertise in providing an array of risk
8 management services as we outline earlier in this Rebuttal Testimony. These bidders desire
9 to and do indeed compete to do so at the lowest cost. (Note, on the other hand, under the
10 Managed Portfolio Approach, the utility provides the management services and is not subject
11 to competitive pressures to improve its service and lower its costs.)

12 The successful track record of competition in FRS procurements is evidenced in post-
13 procurement reports in various jurisdictions. For instance, the FirstEnergy-Ohio utilities held
14 a procurement for FRS products earlier this year that attracted 12 bidders and resulted in nine
15 (9) different winning bidders.⁶⁴ The PUC-Ohio's Chairman Alan R. Schriber remarked:

16 We are more than pleased that ratepayers in northern Ohio, many of whom
17 have been victimized by the economy, will benefit from the outcome of
18 this energy auction . . . We're proud of the way the auction was conducted
19 and commend the participants, the auction manager and our consultant for
20 making this such a success.⁶⁵

⁶⁴ See *New Release: PUCO Accepts FirstEnergy Auction Results*, Public Utilities Commission of Ohio ("PUC-Ohio") Case No. 08-935-EL-SSO (issued May 14, 2009) ("PUC-Ohio May 2009 Release"). See also *Finding and Order*, PUC-Ohio Case Nos. 08-935-EL-SSO, 09-21-EL-ATA, 09-22-EL-AEM and 09-23-EL-AAM (issued May 14, 2009).

⁶⁵ PUC-Ohio May 2009 Release at p.1.

1 New Jersey’s competitive procurement for FRS products in February of this year resulted in
2 11 different *winning* bidders.⁶⁶ Maryland’s FRS Structure elicited participation from 22
3 qualified bidders in its April 2009 procurement process for procuring SOS load.⁶⁷ That April
4 2009 RFP resulted in ten (10) different winning bidders.⁶⁸

5 The Connecticut Department of Public Utility Control (“CT DPUC”) in the same way
6 issued a report on The Connecticut Light and Power Company’s (“CL&P”) September 2007
7 Default Service procurement, in which CL&P used a similar FRS procurement process.⁶⁹ In
8 approving the CL&P RFP results in its September 26, 2007 Decision, the CT DPUC noted
9 that the “total number of bids is the largest submitted to date in any round, and more bidders
10 participated in this round than in any previous [SOS] solicitation.”⁷⁰

11 In this way, to the extent that National Grid seeks products similar to those procured in
12 various competitive states throughout the U.S., the FRS Structure, all else being equal, will
13 promote robust levels of participation due to its well-designed, stable and non-discriminatory
14 procurement process. The FRS Structure will be most likely to result in favorable SOS
15 supply contracts by delivering competitively-priced products directly to customers that take

⁶⁶ See *Decision and Order*, State of New Jersey Board of Public Utilities (“NJ BPU”) Docket No. ER08050310 (issued Feb. 6, 2009). See also *Annual Final Report on the 2009 BGS FP and CIEP Auctions*, Boston Pacific Company, Inc., NJ BPU Docket No. ER08050310 (filed Apr. 22, 2009) (“2009 NJ Auction Report”).

⁶⁷ See *Direct Testimony of Richard A. Mazzini, The Liberty Consulting Group, on Behalf of the Staff of the Public Service Commission of Maryland*, Maryland Public Service Commission Case No. 9056 (filed Apr. 23, 2009).

⁶⁹ See *Decision in Re: DPUC Development and Review of Standard Service and Supplier of Last Resort Service – Review of CL&P’s 4th Standard Service Auction*, CT DPUC Docket No. 06-01-08PH02 (issued Sept. 26, 2007) (“CL&P RFP Decision”).

⁷⁰ CL&P RFP Decision at p.18.

1 SOS from National Grid, bringing the advantages of a competitive marketplace to customers
2 even if they are not taking service from competitive retail suppliers.

3 **Q. WHICH OF THE PROCUREMENT STRUCTURES WILL BETTER PROMOTE**
4 **RETAIL COMPETITION?**

5 **A.** As we have discussed in detail in this Rebuttal Testimony, it is clear that the FRS Structure
6 will facilitate and encourage retail competition more effectively than Mr. Hahn’s Managed
7 Portfolio Approach.

8 *i It cannot be disputed that National Grid’s SOS obligations must always be*
9 *met by full requirements service, whether the Commission adopts a FRS*
10 *Structure or Mr. Hahn’s Managed Portfolio Approach, though a FRS*
11 *Structure will best meet these full requirements needs.*

12 **Q. FINALLY, HOW DO YOU RESPOND TO MR. HAHN’S STATEMENT THAT**
13 **NATIONAL GRID’S “SOS LOAD OBLIGATIONS [MUST NOT] ALWAYS BE MET**
14 **BY FULL REQUIREMENTS SERVICE”?**⁷¹

15 **A.** Mr. Hahn must have misunderstood Mr. Daniels testimony if he takes issues with his
16 statement that SOS load obligations must always be met with full requirements services, as
17 this is an undisputable fact. Regardless of the approach adopted by this Commission,
18 National Grid *must meet all of its SOS customers’ load requirements at all hours of every*
19 *day.* This is the definition of “full requirements service.” National Grid can meet this
20 obligation to provide FRS either by parsing up its obligations and bidding out FRS contracts
21 for portions of its load, or it may pursue Mr. Hahn’s proposal to on its own manage, procure
22 and predict changes for each of the components required to provide such FRS for the entirety
23 of National Grid’s load.

⁷¹ RIDPUC-Hahn Direct at p.34 (lines 19-20).

1 **3. Summary.**

2 **Q. CAN YOU PLEASE PROVIDE A SUMMARY OF YOUR THOUGHTS ON THE**
3 **APPROPRIATE STRUCTURE FOR PROCURING NATIONAL GRID'S SOS**
4 **OBLIGATIONS?**

5 **A.** Certainly. FRS products relieve utilities such as National Grid from active load, weather and
6 market volatility management responsibility and, in turn, relieve such utilities and their
7 customers from risk management exposure. FRS products more effectively eliminate the
8 uncertainty associated with fuel, availability, volumetric and spot price risks that are inherent
9 in managing load supply. These FRS products have the added benefit of avoiding after-the-
10 fact reviews that may question the effectiveness or reasonableness of hedges necessary to
11 limit risk. Furthermore, potential bidders are interested in well-defined FRS products and are
12 comfortable with pricing such products through competitive processes such as the
13 procurements in the FRS Structure.

14 In summary, the FRS Structure relying largely on FRS products will most effectively and
15 best meet National Grid's SOS customers' needs. Moreover, it is best to rely on such FRS
16 products to allocate to wholesale suppliers – rather than National Grid and, in turn, its SOS
17 consumers – the risks and responsibilities associated with portfolio management. As the
18 Analysis Group Study states succinctly:

1 It is the experienced participants in wholesale markets who take on the tasks
2 of developing a portfolio of resources, making physical arrangements to lock-
3 in certain supply, arranging for transmission of the supplies, making financial
4 arrangements to hedge their financial and price risk, and offering to sell at a
5 fixed price offer in competition with other suppliers.⁷²

6 Wholesale suppliers who submit bids in the FRS Structure's procurements will be in the best
7 positions and will be best equipped to bear such risks and responsibilities.

8 **Q. DOES THAT CONCLUDE YOUR JOINT REBUTTAL TESTIMONY?**

9 **A. Yes.**

⁷² Analysis Group Study at p.11.

EXHIBIT 2.1

RESUME OF DANIEL W. ALLEGRETTI

Daniel W. Allegretti
One Essex Drive
Bow, New Hampshire
(603) 224-9653

Experience

2009-Present - Constellation Energy Resources, LLC
Baltimore, Maryland
Vice President Energy Policy

- Advocate, testify and generally represent the interests of the company before federal, state and provincial agencies, executive departments and legislative bodies, and within regional transmission organizations, throughout the Northeastern United States and Eastern Canada.
- Supervised a staff of six professionals who advocate and represent company interests under my direction across the Eastern Seaboard region.
- Provide direct business support to internal teams who originate new business transactions or who manage an active portfolio in support of existing business.
- Maintain and expand a network of contacts and relationships within industry and government to support regulatory and legislative advocacy and information gathering.

2008-2009 – Anbaric Northeast Transmission Development Company, LLC, Wakefield, MA
Senior Vice President

- Conceived, developed and promoted multi-billion dollar independent transmission projects in the Northeastern United States and Canada.
- Represented Anbaric before state, federal and provincial governmental entities and before non-profit and industry organizations.

1996-2001 - Enron Corp., Houston, TX
Director, Government Affairs

- Advocated on behalf of industry-leading company before state utility commissions, executive departments and state legislatures during the critical transformation from regulated monopoly electric

service to competitive wholesale and retail electricity markets in New England.

- Represented company within the New England Power Pool organization during the development of a region-wide transmission tariff, organized wholesale electricity markets and creation of an independent system operator. Provided leadership in the reform of NEPOOL governance to include all industry sectors and was elected NEPOOL chairman in 2000.
- Provided direct business support to wholesale business origination, retail sales and wholesale power marketing and trading businesses.

1989-1995 - Brown, Olson & Wilson. Concord, NH Attorney

- Represented independent power developers, municipal governments and energy trading companies before state and federal agencies and courts and in contract and settlement negotiations.
- Conducted research, met with clients and prepared, filed or submitted a variety of legal memoranda, briefs, contract documents and consulting reports.

Education

1985-1988 - Georgetown University Law Center, Washington, D.C.

- Completed *juris doctor* degree
- Completed internships with U.S. International Trade Commissioner, U.S. Court of Appeals judge and U.S. Senator
- Admitted to the bar in DC, MA and NH

1981-1985 - Colby College, Waterville, Maine

- B.A., Economics, French (*cum laude*, phi beta kappa)

Honors/Positions

- New England Power Pool
 - Chairman Nepool Participants Committee (2001 & 2002)
 - Chairman Nepool Budget & Finance Subcommittee (2005)
 - NEPOOL Supplier Sector elected representative (1996-2006)
 - Chair of various *ad hoc* Nepool committees and working groups (1996-2005)
- Board of Directors, Northeast Power Coordinating Council (2001-2008)
- Board of Directors Independent Power Producers of New York (2002-2008)

- Board of Directors, Electric Power Generators Association of Pennsylvania (2008)
- Management Committee, New York Independent System Operator (2002-2005)
- Maine Energy Advisory Council (appointed by Governor in 2006)
- Ontario Independent Electric System Operator, Market Advisory Council (2002-2005)
- Ontario Electric Markets Investment Group, governing body (2002-2005)

EXHIBIT 2.2

ANALYSIS GROUP STUDY



ANALYSIS GROUP
ECONOMIC, FINANCIAL and STRATEGY CONSULTANTS

Pennsylvania's Electric Power Future: Trends and Guiding Principles

Susan F. Tierney, Ph.D.
Analysis Group

Boston, Massachusetts
January 2008

This White Paper was commissioned by Energy Association of Pennsylvania. This paper represents the views of the author, and not necessarily the views of the Energy Association, its members, its affiliates, or the employer of the author.



**PENNSYLVANIA'S ELECTRIC POWER FUTURE:
TRENDS AND GUIDING PRINCIPLES**

Susan F. Tierney, Ph.D., Analysis Group

January, 2008

EXECUTIVE SUMMARY

Pennsylvanians have benefited from stable electricity prices over the past decade – a situation enabled to a large degree by a package of reforms adopted by the General Assembly in the Commonwealth's Electric Generation Customer Choice and Competition Act of 1996. When that law was passed, Pennsylvania's electricity rates were among the highest in the country. Over the past decade, consumers in most other parts of the country have seen their electricity prices rise much higher than in Pennsylvania. In fact, price increases in Pennsylvania have been relatively small, at one-half the rate of inflation. Unlike a decade ago, Pennsylvania's electricity rates are now lower than the national average. Studies show that competitive markets have introduced positive changes in the states where restructuring has occurred. Pennsylvania policy makers should stay the course and support the development of competitive markets in the Commonwealth.

Looking ahead as rate caps for the remaining Pennsylvania electric utilities expire, various stakeholders have been exploring the best ways to help steer the state's passage through the upcoming transition to a world of relatively higher electricity prices that reflect the current cost of supplying electricity. The Pennsylvania Public Utility Commission, for example, with the participation of various consumer, utility, power suppliers, environmental, and others, recently adopted a strategy for preparing Pennsylvanians to understand and mitigate the impacts of future increases in power supply costs. Governor Rendell and the Pennsylvania General Assembly are considering ways to educate consumers, provide tools for enabling consumers to manage their energy use, and ensure increased reliance on competitively sourced alternative energy products.

Readying consumers for a future reflecting current energy-market conditions is key for leaders in the Commonwealth. Taking the right steps will require an understanding of some of the underlying trends and opportunities for prudent leadership. This should involve resisting – for all the right reasons – the natural tendency to want to “fix” prices when they rise. And Pennsylvanians will become better able to manage their energy use in the future if they are equipped with the right tools to do so.

This paper is designed to provide some information and guidance as Pennsylvania looks ahead to its power future. The paper does so by explaining first some of the defining trends in the electric industry, and then provides four principles to help guide the Commonwealth's path toward reasonable approaches for determining electricity pricing and procurement in the years ahead.

Trends and guiding principles for PA's electric future

Explained more fully below, several defining trends in the electric industry are as follows:

- **Restructured power markets have provided measurable benefits for consumers.** These benefits include those identified as goals in Pennsylvania's own Electricity Generation Customer Choice and Competition Act of 1996: to rely on "competitive market forces [which] are more effective than economic regulation in controlling the cost of generating electricity," to bring about innovation and improvements in risk management; and to allow consumers to make choices about their power suppliers. Other outcomes have included greater development of renewable resources and technologies designed to assist consumers to reduce their demand for power.
- **Even so, higher electricity prices are occurring in both regulated and restructured states, and the result of fundamental changes in global markets for fossil fuels.** Higher prices also stem the need to address other critical economic and social challenges such as reducing greenhouse gas emissions from power production, continued demand for reliable power, and aging infrastructure.
- **Electricity still provides high value, with prices much lower today than they were 20 years ago, when adjusted for inflation.** Compared to many other goods and services we depend upon in our daily lives, electricity still remains a relative bargain. Across the U.S., taking inflation into account, prices are still only about 2/3rd of what they were at their highest in the early 1980s. Similarly, as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than it did during the 1980s. Electricity prices have risen more slowly than those for other goods and services (especially including heating oil, gasoline, and natural gas delivered to commercial users and to home). At the same time, more electricity is being used than in the past, as we depend upon electronic systems for more of our basic services.

With these trends in mind, several reasonable principles can help Pennsylvanians' transition to the next chapter of the Commonwealth's electric industry and to ready them for what will be required to help keep Pennsylvania's economy vibrant, and innovative. These principles are summarized here and explained in greater detail below.

- **Pennsylvania policy makers should continue to support competitive markets; a stable regulatory environment will attract capital investment needed to meet Pennsylvania's power requirements.** The Commonwealth's economy, and its goals for an innovative and modern energy sector, depend upon attracting capital. Building on the current regulatory and market structure, and making incremental policy changes (rather than substantial redesigns of the industry) will help create the investment climate needed for Pennsylvania to achieve its energy goals.
- **Policy makers should heed the lessons learned when rate freezes were imposed at levels out of line with market conditions.** California's ill-fated electricity crisis in 2000-2001 was made worse when state policy makers continued retail price caps at a time when electricity companies had to buy power at much-higher wholesale market rates. After Pennsylvania's rate freezes expire in upcoming years, those companies cannot avoid obtaining power at current market prices. At that point in time, extending rates at current levels would be identical to imposing

Trends and guiding principles for PA's electric future

entirely new rate raps, since those rates reflected agreements and conditions designed for a fixed transition period. California's experience warns that keeping rate freezes in place when utilities must procure power at costs well above the rap cap would impose dire financial consequences for those companies, send signals to investors that are opposite from the investment-friendly climate the state hopes for, and will raise costs to consumers in the long run.

- **Other available tools, not rate caps, can help electricity consumers manage their energy needs in the future.** Adopting new regulatory policies that support electric companies providing electricity customers with the kind of information, service and product options, and other types of assistance they need will help Pennsylvanians better manage their energy needs and control their electricity expenditures in the 21st century. Among the policies to support this result are well-designed phase-in mechanisms to bring customers' rates gradually to market prices, instituting incentives for adoption of advanced metering, use of better pricing options, services and technology packages to enable electricity customers to better manage their own demand and thus allow the chance for more vibrant retail choice to develop, and providing programs to assist low-income customers.
- **Well-designed power market policies and rules matter, for keeping prices to consumers as low as possible.** These policies and rules are still evolving, and include well-designed and implemented competitive power procurement processes that enable electric distribution utilities to obtain power supplies for those customers who do not elect to buy power from a competitive supplier. Great attention still needs to be paid to refining these and other policies to help Pennsylvania move through this transition and allow its citizens to get the benefits of a clean, efficient, reliable, and more secure electricity future.

So, while we can expect a "new normal" of higher electricity prices in the electric industry for the foreseeable future, we can also hope for a strong electric industry, able to provide Pennsylvanians with the energy infrastructure and services they will need. Presuming a degree of regulatory and policy stability going forward and reliance to a considerable degree on market forces, we can expect private investors to supply capital for the grid, for greater improvements in energy efficiency, and for development of more innovative power production facilities consistent with a carbon-constrained economy. And we can expect electricity users to have the information, services, and technologies they will need to better manage their own power needs and keep electricity as affordable as possible. All of this is good for consumers.

KEY TRENDS IN THE ELECTRIC INDUSTRY

1. RESTRUCTURED POWER MARKETS HAVE PROVIDED MEASURABLE BENEFITS FOR CONSUMERS.

Since restructuring its electric industry a decade ago, Pennsylvania, like the other third of the states that did the same, has a different electric industry and system today than it did in the past. Pennsylvania's policies allow suppliers other than electric utilities to provide power to consumers, afforded non-utility generators the opportunity to buy utility power plants, opened up and created incentives in the power sector for greater competition, investment and performance efficiencies, moved to market mechanisms as the means to set electricity prices, and so forth. Many regions (including the PJM power region, in which Pennsylvania is located) developed Regional Transmission Organizations ("RTOs") to independently operate the grid and to administer wholesale power markets, using them to determine efficient dispatch as well as market-clearing prices.

For the most part, the states that pursued early efforts to restructure their electric industries were ones that (like Pennsylvania) already had high electricity prices during the 1990s. These were states where at the time, a number of features — rate increases associated with new power plant investment, cost overruns, expensive long-term contracts, combined with opportunities to build new generating capacity at costs lower than prevailing electricity prices — motivated large electricity consumers (and their political representatives) to complain about utilities' high price levels under traditional regulation and seek the option to buy power directly from the electricity supplier of their choice. Almost all of the states that now have higher-than-average retail electricity rates were also among the states with higher-than-average rates on the eve of restructuring the electric industry in 1996.¹ Over the past decade, the gap has narrowed between the prices in the high-cost states that restructured and the prices in the states that did not.²

There were many motivations at the roots of these past efforts to introduce competition into the electric industry. As Pennsylvania's electric competition act declared, "competitive market forces are more effective than economic regulation in controlling the cost of generating electricity." There were desires to reduce the influence of utilities' preferences for rate-base investments over other alternatives that might have provided greater consumer benefits; hopes to bring about innovation and improvements in risk management; and the goal of allowing consumers to make choices about their power suppliers. To date, some of these benefits have transpired; others are still a work in process.³

For example, the nation's overall mix of power plants is now much more efficient than in the past. Today's markets have provided incentives for producers to make needed investments and improvements in operating practices, with cost savings⁴ and other improvements resulting in increases in the efficiency of fuel-consumption of fossil fuel-fired facilities;⁵ decreases in the length of refueling outages, lower operations and maintenance expenses, and greater plant availability at nuclear facilities;⁶ and decreases in operations and maintenance costs across all facilities.⁷ Improvements that increase plant availability are particularly valuable because they increase the quantity of power produced by less-costly power facilities.⁸ Also, restructured wholesale markets have improved the efficiency by which plants are "dispatched" (i.e., turned on and off) to meet consumer demand.⁹ Certain long-standing barriers to efficient trade across regions (e.g., "pancaked" layers of transmission rates needed to transport power across multiple regions) have been reduced or

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for their electricity, there are good examples around the country of states (e.g., New Jersey, Massachusetts) where proactive communications, combined with well-planned measures to phase-in and blend-in higher market prices, have allowed a smooth transition from capped rates to today's prices.

2. HIGHER ELECTRICITY PRICES ARE OCCURRING BOTH IN STATES THAT RESTRUCTURED THEIR ELECTRIC INDUSTRIES AND THOSE THAT DID NOT.

Around the country, higher electricity prices are the "new normal" for most Americans. No consumer likes price increases of any kind, let alone those we feel we can't control and for things – like electricity – we absolutely need. We depend upon having electricity, whenever we need and want it to power so many activities essential (and not so essential) to our daily lives. Our modern society has such a deep dependency on electricity, not just for basic necessities like light and cooling and communications, but for all of the wonderful devices and gadgets it powers. Because we tend to take reliable power supply for granted, we somehow also expect to have it at low rates.

But the reality of conditions in today's global energy markets make it unlikely that low electricity prices will prevail in the future, in Pennsylvania or anywhere in the U.S. The average American has seen prices go up about a third over the past decade. The price of power has been rising for several reasons. Fossil fuels — that is, natural gas, oil, and coal supplies, which together produce over 70 percent of the nation's power¹⁶ — have had significant price increases in the past few years after a period of comparative calm during the 1990s. Natural gas prices shot up starting in late 1999, as North American markets tightened. While natural gas prices have dropped since they spiked following the Hurricanes of 2005, they still remain relatively high, and are not likely to drop any time soon. Even coal — the lowest-cost fossil fuel, used to produce over half of the power generated in the U.S. — has experienced 40-percent price increases since 2000.¹⁷ Electricity prices generally track changes in fossil fuel prices over time, with prices beginning to rise starting around 2000.¹⁸

Increases in fossil fuel prices affect electricity prices differently in different parts of the nation, because of regional differences in the fuels used to generate power. Regions (like New England, California, and Texas) that rely significantly on natural gas to produce power have relatively high electricity prices, while other parts of the country (such as the PJM region (which includes Pennsylvania), the South, and the Mountain states) that produce more than 50 percent of their power from coal have among the lowest electricity rates in the country. Nearly all of the 30 states (like Pennsylvania) with below-average electricity rates in 2006 are in regions with a high percentage of power produced by coal.¹⁹

Other things also contributed to high electricity prices. New investment has been needed to keep the lights on and reduce environmental impacts from generating electricity. From 2000 to summer of 2007, U.S. households, businesses, factories and others together increased use by more than a state of Texas-sized amount of new demand.²⁰ During that period, more than 210,000 MW of new power plant capacity went into operation – roughly equivalent to adding one large power plant a week over the entire period.²¹ Using a conservative, back-of-the-envelope estimate, this represents an investment of roughly \$100 billion across the country, just to keep pace with new demand and plant retirements.²²

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Other costs have also begun to drive up electricity prices. From 2002 through 2005,²³ electric companies spent more than \$21 billion to comply with federal environmental laws adopted to address health problems associated with air and water pollution. These costs have already begun to show up in electricity prices. Utilities' annual investment in transmission and distribution systems amounted to approximately \$24.2 billion in 2006, up from \$10.4 billion in 1995.²⁴ Over 2,500 miles of high voltage transmission lines were added in 2005 alone — equivalent to a new line stretching most of the way across the U.S.²⁵ The price of construction materials (like iron, steel, cement and concrete) has risen sharply in recent years, further increasing costs to build energy facilities.²⁶

The effects of these factors are likely to persist for the foreseeable future. Electricity prices, like fossil fuel prices, are expected to remain high in the near and longer term.²⁷ The same is true for investment requirements. The U.S. government estimates that 258,000 MW of new capacity is needed between 2006 and 2030, equivalent to four new "Texan"-size electrical additions and a total investment of \$412 billion (2005 dollars) — or even higher, if today's high construction-related cost increases continue.²⁸ Further, grid operators are seeing significant new investment requirements to expand and upgrade regional power service.²⁹ Installing more advanced metering, energy efficiency and other demand-side technologies to enable consumers to see and better manage their electrical use and even avoid the need for new power plants also come at a cost. Meeting existing clean-air regulations will cost the electric industry an additional \$2.7 billion a year in 2010, and \$4.4 billion in 2015.³⁰ And the cost of controlling carbon emissions from electricity production and use (which account for approximately 40 percent of U.S. CO² emissions, or nearly 10 percent of worldwide CO² emissions³¹), will inevitably increase in the future, and indeed need to begin to show up in prices in order to induce the kind of technological innovation required to meet the nation's electricity needs in a carbon-constrained world.

In light of these costs, it is simply unrealistic to expect that electricity prices are going to be lower in the near future. It seems reasonable to equip Pennsylvanians with this information so that they can begin to prepare for a different set of conditions in the future than they enjoyed in the past.

3. ALTHOUGH PRICES ARE RISING, ELECTRICITY STILL PROVIDES HIGH VALUE.

Compared to many other goods and services we depend upon in our daily lives, electricity still remains a relative bargain. Across the U.S., taking inflation into account, prices are still only about 2/3rd of what they were at their highest in the early 1980s. (See Figures 2.a and 2.b, below.) Similarly, as a percentage of gross national product, the U.S. spends about 2/3rd less on electricity than it did during the 1980s. Electricity prices have risen more slowly than those for other goods and services (see Figure 3). And from 1999 through 2006, electricity price increases were far lower than those for heating oil, gasoline, and natural gas delivered to commercial users and to home.

In fact, households spend no more (as a percentage of median income) on electricity than they did a decade ago, yet the average American is using much more electricity than in the past.³² That we use more power today is hardly surprising, given the significant increase in electronic consumer products and in the many technologies and tools in our offices, shops and factories that depend on reliable electricity supplies. Every cell phone charger, every plasma TV, every computer, every ATM, every new cooler at the local convenience store,

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and every air conditioner adds to our power requirements. Overall, our standard of living depends on having access to electric power.

Figure 2

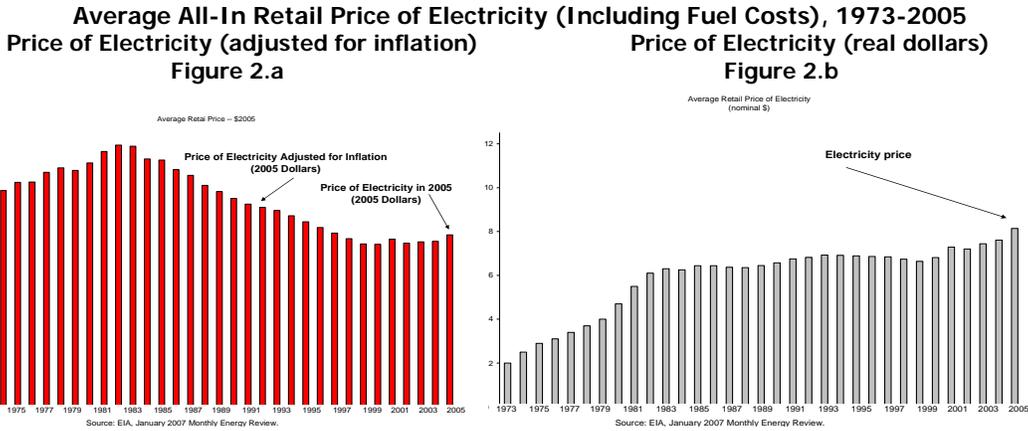
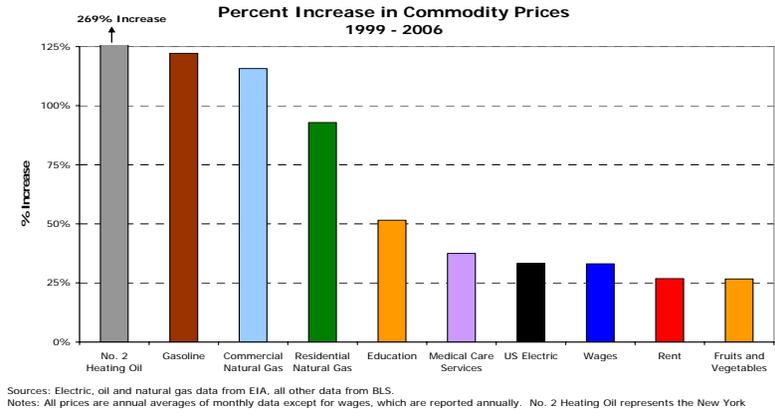


Figure 3



IMPORTANT PRINCIPLES TO GUIDE THE TRANSITION TO THE NEXT CHAPTER OF PENNSYLVANIA'S ELECTRIC INDUSTRY

- 1. STAYING THE COURSE AND SUPPORTING COMPETITIVE MARKETS WILL HELP PENNSYLVANIA ATTRACT THE CAPITAL INVESTMENT NEEDED TO MEET ITS NEEDS FOR CLEAN, RELIABLE AND AFFORDABLE POWER AND TO ASSIST CUSTOMERS IN MANAGING THEIR OWN ELECTRICITY BILLS.**

At the end of 2007, across the U.S., the electric industry finds itself in a situation where approximately one-third of the states (representing 2/5 of the sales of electricity around the country) are now pursuing a competitive market model for the electric industry in their state. These restructuring reforms tended to occur in states, like Pennsylvania, with high electricity prices at the time. The purpose of these reforms was to allow for greater reliance on market forces to determine the mix of resources and the allocation of risk between investors and consumers, and to allow customers to exercise greater choice in satisfying their own energy requirements. Typically, these states implemented these reforms through a process that

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included a transition period before moving to more full-fledged competition. Some of those states still find themselves in that transition, as do parts of Pennsylvania. The other two-thirds of the states retained the core structural elements of their traditional regulatory model, in which electric utilities typically own generation, transmission and distribution, with many costs and investments of the privately owned utilities subject to state rate regulation. Both types of states' electric industries operate – to a greater or lesser degree – within the context of national policy that embraces competition in wholesale power markets, with that competition enabled through a requirement for generation suppliers having non-discriminatory access to transmission facilities and interconnected markets.

Both types of states and regions – those that have taken a path relying on more competitive structures, and those that have remained on a path of traditionally regulated utility structures – will require investment to assure adequate electricity supplies in the future. A factor that likely would undermine the ability of electric companies in *either* part of the country to attract investment capital is uncertainty about the rules of the road going forward. Material uncertainty in the regulatory structure, in the investment recovery rules, and so forth, will raise the cost of doing business as compared to environments where there is a relatively stable regulatory framework in place.

Recently, many people have questioned whether the right road was taken in one state or another, and what reforms are now needed to bring things back on track. Some suggest a return to what they view as a more protective set of arrangements they associate with regulation. In many respects, this overlooks the fact that traditional regulation also has had its own notorious problems. Many scholars and industry experts have studied these issues, and most tend to conclude that we should remember that there were no “good old days” and that traditional regulation had significant (although different) problems of its own.³³

In light of this, a useful foundation for constructive discussions in this industry is the notion that neither regulation nor competition is perfect. This provides a basis for a reality-based dialogue — one that gravitates towards finding improvements in industry approaches already in place in a particular region, rather than attempts to throw out the current industry model in hopes that the alternative will be something better. This will support the kind of stable regulatory environment that investors find attractive.

This point is particularly important, given that the electric industry is inherently technology-based and capital-intensive investment (whether baseload generation, or transmission, or renewables, or even many energy efficiency installations). This industry has always operated through complex, enormously technical, engineered systems of generators, transmission lines, distribution systems, and a variety of control technologies.

Given the need to attract prudent investment in new electric generation and demand management technologies, it seems as important to create an environment of regulatory stability. New, innovative types of electric resources and technologies are necessary for assuring that the next vintage of long-lived power plant investments are clean and efficient, so that (among other things) the carbon emissions from the electric industry begin to decline in ways that mitigate emissions contributing to climate change. Technology is also required — and already available — for enhanced, more reliable and more secure transmission investments, allowing for a more robust electric system that positions the U.S. for the needs of the 21st century. Additionally, many of the technologies for enabling customers to better manage and make efficient use of electricity are already known, but have only been deployed in very limited contexts. Achieving the economic, reliability and environmental

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benefits of technology adoption is critically important for the country, but depends upon keeping an eye of improving, rather than making more chaotic, the rules of the road.

2. POLICY MAKERS SHOULD HEED THE LESSONS LEARNED IN OTHER STATES WHEN RATE FREEZES WERE IMPOSED AT LEVELS OUT OF LINE WITH FUNDAMENTAL MARKET CONDITIONS.

When most states restructured their industries a decade ago, they adopted a package of reforms designed to make the electric industry more efficient, to provide consumers with prices disciplined by market forces, to cause electric suppliers to internalize the risks of certain types of investment decisions, and to transition to a fully competitive retail and wholesale power market. Many of these states, like Pennsylvania, adopted a package that also included elements (such as rate caps to be in place over a temporary and predetermined time frame) designed for fairness, efficiency and "orderly transition" goals.³⁴

At the time these packages of reforms were implemented, most states ensured that the pieces were in place so that customers would be assured the possibility of continuing to take service at a regulated (and in many cases, frozen or capped) rate for a defined period of time. In most states, this meant that the electric utility would have continuing obligations to provide generation service to customers even though it did not have supplies; therefore, it would need to arrange with a third-party to provide it with wholesale supply for this purpose. The third-party competitive supplier would know, at the time it signed up for this commitment, the terms and conditions under which it would provide supply. Typically, there was a clear end date of the supply contract, often timed with the end of the transition period's rate freeze. This provided the sort of financially viable, symmetrical contractual arrangement that would (a) assure customers with power at fixed prices, (b) ensure that that power would be provided by a willing seller at the terms and conditions established at the time the contract was signed, and (c) keep the utility, in its role as the "agent" for the retail basic service customers, in a financially neutral fashion, neither earning a return on this function nor taking financial risk. In essence, this is the type of workable arrangement in place for each of Pennsylvania's utilities that have been providing fixed price basic service to consumers during each utility's transition period.

A notorious example of a state that drastically erred in extending its rate caps is California. When California restructured its electric industry in the mid-1990s, the rules required the utilities to provide basic service to consumers at a fixed (capped) rate, set in motion the divestiture of utilities' power plants, and required the utilities to buy all of their daily power supply needs for their basic service customers in the marketplace. This arrangement collapsed in 2000/2001, when prices in wholesale markets began to diverge – first somewhat, and then to a dramatic degree – from the capped retail prices. The situation was ultimately – and fundamentally – not sustainable. As the spread between capped rates to consumers and wholesale power supply prices widened over time, utilities had to spend more to buy power from third parties than the utility could ever hope to collect from consumers. Eventually, California's investor-owned utilities lost their credit-worthiness, one (PG&E) declared bankruptcy and another (SoCal Edison) barely avoided doing so. As a result, the State of California stepped in to contract for supplies under emergency conditions, hardly an opportune time to be contracting for power. While California's experience was clouded by a number of other well-chronicled problems, one central issue that led to financial problems for nearly everyone was the state's policy that required, in essence, that utilities sell power for their retail basic-service customers at capped rates even

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as those utilities had to purchase power at higher market-based rates. The political, financial, and economic fallout of the cascading set of problems is well known to industry and lay observers, alike.

California's experience provides an important lesson for any state considering whether to impose or extend a rate cap when market conditions have significantly diverged from the price levels at which the rate freeze was (or is) set. It is a reckless strategy, entirely inconsistent with either the competitive market model for the electric industry or the regulated, cost-of-service model. The latter, more traditional approach is one in which the utility is obligated to provide service to consumers and to be compensated for doing so at just and reasonable rates; long-standing regulatory practice as well as court decisions support the premise that the utility's rates are just and reasonable when they provide the opportunity for the utility to recover its costs and earn a fair return on its investment. Imposing rate freezes at levels out of line with market conditions violates that balance between the utility's obligation (to provide service) and its rights (to be permitted to charge rates that allow it the opportunity to earn a fair return).

Today, extending rate caps at current levels (i.e., at levels well below current market prices) at a time when there is no expectation that market prices will actually go down in the future is surely a formula for disaster. This strategy should be understood as genuinely being "too good to be true." And therefore not viable. It will be damaging to a utility's financial health. And it is also likely to impede the development of retail markets, keeping customers from seeing and understanding the true cost of electricity in today's conditions, and inappropriately dampening demand response.

A decade ago, in adopting the Electric Competition Act, Pennsylvania's leaders understood the importance of ensuring a financially viable utility industry as part of the move toward competition markets. The Act included several provisions to protect against situations where the utility's financial foundation would be materially undermined.³⁵

Policy makers in the Commonwealth today should heed the lessons learned in other regions' power markets when they consider imposing rate freezes out of line with market conditions. California's experience warns that keeping rate freezes at that time would impose dire financial consequences for those companies, send the signals to investors that are opposite to the investment-friendly climate that the state is hoping for, and will raise costs to consumers in the long run. After Pennsylvania's rate freezes expire in upcoming years, those companies cannot avoid obtaining power at current market prices. They no longer own the generation needed to supply the needs of their customers and even if they did, they could not avoid paying the current market price for fuel to generate electricity. And it is that fuel price that is the primary driver for increased electric prices.

3. OTHER AVAILABLE TOOLS, NOT RATE CAPS, CAN HELP ELECTRICITY CONSUMERS MANAGE THEIR ELECTRIC BUDGETS IN THE FACE OF HIGHER ELECTRICITY PRICES.

As many states have emerged at the end of their transition periods, some have navigated the path more smoothly than others. The experience in other states provides some useful guidance about what to do – and what to avoid – as Pennsylvania transitions to providing consumers with prices reflecting today's market realities. It will be critical to adopt new regulatory policies that build on and fit with the core features of the path towards

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competition that Pennsylvania's electric industry has taken over the past decade. Then, shaping those policy refinements so as to provide electricity customers with the kind of information, service and product options, and other types of assistance they need will help Pennsylvanians better manage their energy needs and control their electricity expenditures. Policies consistent with this objective involve allowing more vibrant retail choice to develop, adopting incentives for advanced metering, offering customers better pricing options, services and technology packages to enable them to better manage demand, and programs to assist low-income customers.

Best practices for emerging from the transition period's capped rates. Best practices include: strong consumer education in advance of the shift from capped rates to market-based rates; information about the changes that have occurred in external fuel markets and other trends that lead to higher prices; new rounds of information to inform consumers about the types of products and services available from alternative suppliers; targeted assistance to low-income consumers; provision of an array of energy-efficiency and demand-side measures to consumers, timed before or in conjunction with the move to market-based rates; adoption of advanced metering devices with options for all consumers to buy electricity under time-of-use prices; use of well-designed and implemented competitive procurements for basic generation service to be offered by the local utility (more on this below); phasing in of market-based rates over a time certain. States might also include some use of a form of "shadow pricing" of prices that vary over time, in advance of actually moving to market-based rates.

Things to avoid from experiences of other regions. If there are too many changes going into effect at once, consumers may become overloaded. For example, Illinois learned this lesson when one utility re-allocated costs among customer classes as part of new retail rate designs and put these new rates into effect simultaneously with the move toward market-based generation rates. This type of action can lead to larger-than-expected rate shock for certain customers, even when the overall impact of market-based rates has been well-explained and understood.³⁶ The timing and manner of phasing new market-based rates into effect might be informed by information available on forward market conditions. The more it appears that forward markets are at a particularly high point in normal price cycles across the year (or due to particular unusual events in world fuel markets), the more the state might want to phase-in the full impacts of market prices. This was an important lesson to take away from Maryland's experience, when it went out to markets to procure power supplies just after natural-gas prices soared following the Hurricanes of 2005. The phasing-in of rates is important both in the short run and the long run. In the short run, this helps smooth the effect on electricity consumers' budgets. In the long run, it enables customers to begin to see the true cost to provide them with electricity. Consumers will be better able to manage their own electricity bills if more light is shed on electricity realities.

Other strategies to help consumers emerge from transition periods. There are ways to assist consumers with managing their electric budgets through innovative policies and technology, much of which already exist but await the decisions of policy makers to promote them more aggressively. For example, adoption of higher efficiency standards for consumer appliances sold in the state makes more sense as electricity prices rise and the value of saving energy increases. Advanced building codes for more efficient building design and the adoption of efficient heating and cooling systems (such as distributed generation technologies) will be more attractive for consumers seeking to manage their energy bills. Regulatory policies promoting more aggressive energy efficiency and other demand-side programs are a way for consumers to better manage their power usage and electricity bills. There is a growing

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literature on best practices in regulatory policies and financial incentives to create the right foundations for adoption of cost-effective energy efficiency and load-management measures that provide savings to the consumers who install them but also for the system as a whole.

Also, there are advanced meters and other “smart” equipment that allow customers to see how much it costs to supply power to different appliances at different times of day. There are devices and service providers offering relatively seamless ways to better manage customers’ usage patterns — such as through cycling many customers’ air conditioners in ways that reduces a significant amount of power requirements without reducing comfort or convenience; those who sign up can receive a check for their savings. Large sophisticated users of electricity are already adopting such ways to manage electricity and save money.³⁷ But small users who are shielded from knowledge of the prices to supply power at different times of day have weak (if any) motivation to pursue such devices. The technology, therefore, may exist to keep them informed, but there is insufficient motivation to adopt it.

Enabling this kind of customer response to market conditions is critical to the performance of markets themselves, as well as to the ability of consumers to manage their energy use and electricity bills. The value of harnessing price signals to help supply resources to the system and to discipline prices has been seen in recent years in many RTO-administered wholesale markets. It is no accident that these programs have moved quite aggressively in these markets in recent years, since the transparency of hourly wholesale prices has enabled the possibility of customers seeing electricity prices and making decisions for themselves about whether they prefer to curtail their usage when prices hit a particular threshold.

4. WELL-DESIGNED COMPETITIVE POWER MARKET POLICIES AND RULES MATTER FOR KEEPING PRICES TO CONSUMERS AS LOW AS POSSIBLE.

While today's electricity markets are neither perfect nor fundamentally flawed,³⁸ there are still important elements of market design that would improve their performance, both at the retail and wholesale levels.

In regions with organized wholesale markets, for example, the suggested improvements³⁹ differ by region, but there are some common themes. These include: implementing clear capacity obligations and forward capacity markets to ensure that efficient and adequate investment can take place; further refining and deepening the demand-response side of the market; improving long-term regional transmission planning; allowing long-term financial transmission rights; establishing more precise and consistent definitions of what constitutes workably competitive markets and best practices for monitoring and mitigating markets; improving various “seams” issues at the borders of markets; allowing long-term contracting in ways that align well with organized market design; and better managing the costs to administer wholesale markets. FERC and many states have had a number of these issues on their agendas for some time and have made great strides towards achieving reasonable federal policies. Pennsylvania should continue to support these efforts.

Important refinements in state policies are needed to keep power supply costs as low as possible. Improving price signals to retail consumers so that many fewer see average prices in all hours, will help discipline prices in wholesale markets. So will well-designed and implemented competitive power procurement processes, enabling the local utility to obtain power supplies for those retail customers electing to remain on basic service. As Pennsylvania's rate caps end for all utilities in the future, they will need to arrange for new

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supply for basic service customers for the post-transition periods. Using competitive processes to provide the lowest-cost supplies means that third parties take on market risk rather than having the utility (and by extension, the consumer) do so. In states with retail choice where the local distribution company focuses on “delivering” power and no longer carries out generation functions, the utility no longer has comparative advantages in power markets. Here, the utility provides a basic product – “full-requirements generation service” – and serve as the conduit for these customers in the competitive market place. In this conduit role, the utility calls upon third-party suppliers to provide all of the necessary components of providing supply to customers: energy, capacity, ancillary and other services (such as meeting Alternative Energy Service requirements) at all times and at all levels of customer demand over the course of a day or a season. The utility can make good use of competitive markets to find lowest-cost supplies of “full requirements” power to meet the needs of basic generation service customers; it can do so by defining the product it purchases from competitors, rather than choosing the individual components of a particular portfolio of generation resources used to provide the product. It is the experienced participants in wholesale markets who take on the tasks of developing a portfolio of resources, making physical arrangements to lock-in certain supply, arranging for transmission of the supplies, making financial arrangements to hedge their financial and price risk, and offering to sell at a fixed price offer in competition with other suppliers.

One of the advantages of competition in the procurement of such “all-requirements service” is that it taps into the abilities and skills of different players to develop different and innovative strategies to meet and adapt to power supply conditions as they change in the future. This provides a diversity advantage to consumers. It passes risk from consumers and the utility that is serving as their supply conduit over to the third party suppliers.

Experience in other states' procurements for basic generation service shows that it is possible to design and implement competitive processes so as to hedge price risk. This can be done through staggered procurements that purchase “slices” (or tranches) of supply for different future time periods (e.g., some for six-month contracts, others for longer periods) so as to mitigate the effects of shorter- and longer-term variations in prices. The staggering of procurements and the differing terms of the “slices” of supply thus provide a portfolio that can buffer the effects of otherwise more volatile prices. Additionally, the terms of these procurements can reflect solicitations for suppliers to provide any number of “preferred attributes” reflecting policy preferences of a state or a utility. For example, the procurements could require bidders to provide offers with a percentage of supplies from resources with particular carbon content. The suppliers thus arrange for a package of supplies that integrate different resources with different price, risk, and other attributes needed to meet the needs of basic generation service customers.

In this model, regulators (or other policy makers) specify the types of inputs needed (e.g., whether to require procurement of alternative energy resources) and market participants offer supplies through competitive processes that determine lowest-cost providers of resource portfolios. This contrasts well with alternatives in which the regulator requires the utility to procure particular types of resources (e.g., a procurement of baseload supply), to determine which particular resource(s) to contract with, to determine how that resource fits into an overall portfolio, and in so doing, looks to the regulator to allow it to recover the cost – and risks – of its portfolio management function from consumers. Thus, well-designed and implemented competitive power procurements offer a prudent and efficient means to provide this wholesale supply in ways that provide important benefits to consumers.

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ENDNOTES

¹ Data reflect prices as the end of 2006 (2006 data from EIA, Form 876 data). In 1996, the 19 states (including DC) with above-average electricity rates were (in order, from highest to lowest): Hawaii, New Hampshire, New York, Connecticut, New Jersey, Rhode Island, Alaska, Massachusetts, Vermont, California, Maine, Pennsylvania, Illinois, Arizona, DC, Florida, Michigan, Maryland, and Delaware. In 2006, the higher-than-average-priced states included all of those states (except Pennsylvania, Illinois, Arizona, and Michigan), as well as Texas and Nevada. Note that two high-priced states in 1996 and that restructured their electric industries after then were Pennsylvania and Illinois; both of these were still under rate caps at the end of 2006. All of the high-priced states except Hawaii and Alaska, Florida, and Delaware restructured their electric industries during the past decade.

² These percentages are calculated as the ratio of the average price in restructured states to the average electricity price in non-restructured states. Restructured states were considered to be: Arizona, Connecticut, District of Columbia, Illinois, Maryland, Maine, Massachusetts, Michigan, Montana, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Texas, and Virginia. Data are from EIA, Form 876 data. This trend has also been observed in the research carried out by Howard Axelrod, David DeRamus and Collin Cain and published in "The Fallacy of High Prices," *Public Utilities Fortnightly* (November 2006), page 59.

³ Many observers have commented on the fact that states adopted a complex packages of policies when they adopted as part of the "restructuring" package, with some of these policies – such as multi-year retail rate freezes established at levels below prevailing prices in markets – inhibiting the ability of competitive retail markets to develop over time. On the other hand, such policies were part of the political bargains made to assure decision makers that there would be benefits for all consumers associated with adoption of policies to restructure the industry. See, for example, Ashley Brown, "Retail Procurement: Default Service vs. Monopoly Service Considerations," Presentation to Harvard Electricity Policy Group, October 5, 2007. Furthermore, it is not hard to overstate the inherent difficulty that exists in studying issues relating to the benefits and costs of "restructuring." Any attempts to assess empirically the impact of restructuring on consumer electricity rates must address a number of issues that complicate such an analysis. "The electric industry" varies for electric utilities within states, across states within regions, and even customer classes within individual utilities. Some states started restructuring under conditions of surplus capacity; others did just the opposite. Some had short-lived rate freezes; other still have them in place. Some allowed for retail customer choice for several years, and then switched gears. Some allow pass-through of fuel costs and expenses on a quarterly basis; others allow such costs to be recovered only if there are extraordinary increases. Some have long-term fuel contracts supporting a significant portion of fuel supply; others have contracts whose prices are indexed continuously to changing prices. Some RTOs have experienced several phases of market design since they began operation; others have just recently started to operate their markets. Even with a single RTO, the changes in market rules over time have created different types and degrees of incentives.

⁴ By comparison, under traditional regulation utilities typically do not share in any of the financial gains from improved operating efficiencies. Under cost-of-service regulation, utilities generally recover their operating expenses but are not allowed to share in the savings they might create by increasing operating efficiency to reduce fuel costs or reducing other components of costs. While utilities might be able to share in some savings under certain circumstances (e.g., incentive regulation or due to lags between regulatory proceedings), the fact that savings are shared and often transitory create only partial incentives for utilities to undertake actions to improve plant productivity. Incentive regulation, which allows regulated utilities to share in the savings produced when plants exceed pre-determined performance benchmarks, creates similar incentives to those created by plant divestment. Lags between regulatory proceedings may allow regulated utilities to profit from cost savings until they are incorporated into rates in future periods.) One of the techniques used in many states to enhance such incentives for competition was divestiture of power plants, which in some cases allowed for firms to specialize in the operation of particular types of facilities (such as nuclear plant operations).

⁵ Bushnell and Wolfram (2005).

⁶ Global Energy Decisions (2005); Barmack, Kahn, and Tierney (2006). See, also, Cain and Lesser (2007), who found a 5-percent improvement in nuclear output, with a total efficiency benefit in PJM East's region of approximately \$450 million in annual savings.

⁷ Fabrizio, Rose and Wolfram (2006). See, also, Shanefelter (2006). For example, one study estimated improvements in fossil-fuel plant efficiency of roughly 2 percent, while another study found reductions in labor and operations costs of 3 to 5 percent. (Bushnell and Wolfram (2006) estimate approximately a 2 percent improvement in plant heat rates, which Wolfram (2003) estimates would generate savings of roughly \$3.5 billion annually. Fabrizio, Rose and Wolfram (2006) estimate a 3 to 5 percent reduction in labor and operations costs, which, based on estimates provided by Wolfram (2003), would produce savings of at least \$1 billion annually.) Improvements in the operation of nuclear facilities — where availability and output are estimated to have increased by 10 percent — appear to be largely the result of such consolidation. Although these improvements may not appear dramatic, when aggregated across all facilities, the combined annual savings could be in the billions of dollars.

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⁸ For example, Tierney and Kahn (2007) estimate the savings from increased plant availability in addition along with savings from other elements of restructuring, such as the consolidation of the multiple geographic areas that had previously used for economic plant dispatch.

⁹ Restructuring has facilitated geographic consolidation in a number of ways. One is through the integration of dispatch (or, "unit commitment") decisions that had previously been made within individual sub-regions, such the integration of New York Power Pool sub-regions into the New York ISO. Geographic consolidation also includes integration of regions that were previously in separate RTO/ISOs or dispatch zones, such as the formation of PJM and the recent integration of American Electric Power, Commonwealth Edison, and Dayton Power and Light. One study of geographic consolidation in New York which also examined the impact of reduced outage rates for nuclear and fossil fuel units, found benefits of between \$100 and \$200 million per year, which is roughly 5 percent of the system-wide production and fixed operation and maintenance costs. Tierney and Kahn (2007).

¹⁰ Another study of the benefits of the recent expansion of PJM to include the three Midwest utilities (AEP, ComEd, and DPL) found annual benefits of about \$70 million in PJM and about \$85 million when including regions outside of PJM. The \$85 million annual savings reflects savings across the entire Eastern Interconnect, which spans the majority of the eastern and mid-west states. Global Economic Decisions (2005).

¹¹ In New England, for example, which has studied this issue directly, the region increased its power plant capacity by more than 40 percent (i.e., by nearly 9,800 MW) over the period from 1999 through 2005, with corresponding improvements in heat rates (with lower heat rate reflecting less fuel used to produce power) and overall emissions of carbon dioxide. Source: ISO-NE, Capacity Energy Loads and Transmission Reports ("CELT" Reports) for each year from 1999 through 2006. Capacity data in the table in SECTION I - Summaries Summer - NEPOOL and Total New England August Capabilities and Summer Peak Load Forecast (MW).

¹² <http://www.pjm.com/contributions/news-releases/2007/20080810-demand-response-record.pdf>

¹³ See, for example, the November 2005 letter from seven companies (including Federated Department Stores, WalMart, 7-Eleven, and JC Penny) representing nearly 14,000 facilities and over \$2 billion in annual electricity costs as commercial consumers of electricity. <http://www.competecoalition.com/1115comments.pdf>

¹⁴ The U.S. Electric Energy Market Competition Task Force's Report to Congress on Competition in Wholesale and Retail Markets for Electric Energy (April 2007) provides a good summary of the difficulties experienced in many "retail choice" states in implementing workable competitive markets for small electricity customers.

¹⁵ For example, an increasing percentage of retail customers in the service territories of Duquesne Light and Penn Power (both of whose rate caps have expired) are now being served by an alternative supplier. In Duquesne Light's service territory as of July 2007, 17% of residential customers (representing 16% of residential load), 17% of commercial customers (representing 50% of commercial load), and 44% of industrial customers (representing 88% of industrial load) were served by an alternative supplier for generation service. In Penn Power's area, 8% of residential customers (7% of residential load), 9% of commercial customers (50% of commercial load), and 63% of industrial customers (98% of industrial load) buy power from an alternative supplier. By contrast, companies whose rate caps are still in place have far fewer customers (or customer load) served by competitive suppliers: 0% of PPL's load, 1.5% of MetEd/Penelec's and 2.6% of PECO. <http://www.oca.state.pa.us/Industry/Electric/elecstats/stat0707.pdf>

¹⁶ EIA, <http://www.eia.doe.gov/cneaf/electricity/epa/figes1.html>.

¹⁷ EIA, Coal prices delivered to the power sector. Delivered Price for 1990-2004 from EIA State Data Tables, United States Table 6; for 2005-2006 from June 2007 Electric Power Monthly, Table 4.1.

¹⁸ The strong relationship between changes in fossil fuel prices and changes in electricity prices is explained in more detail in a recent paper I authored, "Decoding Developments in Today's Electric Industry — Ten Points in the Prism," October 2007, prepared at the request of the Electric Power Supply Association. For convenience, I paraphrase footnote 5 from that report: In recent years, many analysts and scholars have studied the relationship between fossil fuel prices and electricity prices. For example, analyzing several decades of annual price data for natural gas and electricity, MIT's Paul Joskow found that there is a close historical relationship between fuel costs and residential and industrial electricity prices. See, Joskow (2006). Young Yoo and Bill Meroney from the staff of the Federal Energy Regulatory Commission found relatively strong explanations for electricity prices increases based on changes in natural gas prices. (Yoo and Meroney (2005).) Ken Rose (2007) observes that natural gas prices have played a role in explaining electricity price changes, along with other important factors including the level of customer load and the existence of different generating technologies (with different power production efficiencies). Greg Basheda et. al. (The Brattle Group), also find that "*Fuel and Purchased Power Cost Increases Have Been Enormous and Are the Largest Cause of Recent Electric Cost Increases*. On an industry-wide basis, our analysis finds that fuel and purchased power costs account for roughly 95 percent of the cost increases experienced by utilities in the last five years. The increases in the cost of these fuels have been unprecedented by historical standards, affecting every major electric industry fuel source." (Basheda et. al., page 2.)"

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¹⁹ 26 of the 30 states with electricity prices below the national average are in regions that produce a significant portion of their power from coal-fired power plants. In most if not all cases, these coal-fired power plants were constructed prior to restructuring.

²⁰ Peak demand increased by 12% over this period. An actual increase of 65,529 MW occurred from 680,941 MW (in 2000) to 746,470 MW (in 2005). Peak demand in 2007 was expected to be approximately, 760,840 MW in the U.S. Thus, an increase of approximately 80,000 MW was expected from 2000 through 2007. Texas' peak demand in the summer of 2006 was over 62,339 MW. Sources: EIA, Electric Power Annual (2006), Table ES1; North American Electricity Reliability Council, Long-Term Reliability Assessment, 2007, Table 32, ftp://www.nerc.com/pub/sys/all_updl/docs/pubs/LTRA2007.pdf, and NERC, "2007 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2007), page 11.

²¹ "One large power plant a week" is based on: Actual net additions of capacity in the U.S. from the end of calendar year 1999 (i.e., the start of 2000) to August 2007 was approximately 210,480 MW. Dividing 210,480 MW by 392 weeks is 536 MW per week, equivalent to a medium-to-large power plant. EIA, Electric Power Annual (2006), Table 2.1 for end of year 1999 (785,927 MW), For capacity in August 2007 (996,410 MW): EIA, Electric Power Monthly, October 2007, Table ES3. New and Planned U.S. Electric Generating Units by Operating Company, Plant and Month, 2007 – 2008. <http://www.eia.doe.gov/cneaf/electricity/epm/epmxfiles3.xls>

²² Actual investment costs are not publicly available. This rough calculation is based on: capital costs of \$550/kW for combined cycle power plants, and \$325/kW for combustion turbine power plants (these two technologies accounted for most of the power plant capacity added during calendar years 2000-2005. These capital cost estimates were from RDI's Outlook for Power in North America 1999 Annual Addition (2000)). The calculation assumed that 2/3rd of the capacity added was in combined cycles, and the rest was combustion turbines. (More recent estimates of capacity costs are much higher. For example, 2001 estimates of capital costs were as follows: \$616/kW to \$800/kW for combined cycles, and CT (2001) of \$400/kW to \$600/kW for combustion turbines (from Barmack, Kahn, Tierney). A recent estimate of capital costs in 2007 is \$800/kW to \$1000/kW for combined cycles, and \$500/kW to \$700/kW (from ISO-NE Scenario Planning Initiative). Sources: EIA, Electric Power Annual 2006, Table ES1; RDI - Outlook for Power in North America - 1999 Annual Edition; Barmack, Kahn, Tierney (2006); http://www.iso-ne.com/committees/comm_wkgrps/otr/sas/mtrls/apr302007/assumptions.pdf.

²³ Smith, Rebecca. "Court Decisions May Aid Some Utility Profits in Long Term," The Wall Street Journal Online. April 3, 2007. Available at: <http://online.wsj.com/article/SB117556293661557706.html?mod=US-Business-News>. Accessed August 24, 2007.

²⁴ Utilities' investments levels were \$14.1 billion in 2000, and \$15.8 billion in 2003. These figures are for shareholder-owned electric utilities. Edison Electric Institute, http://www.eei.org/industry_issues/energy_infrastructure/transmission/Transmission-Investment-Expenditures.pdf (accessed July 28, 2007).

²⁵ NERC, "2006 Summer Assessment: The Reliability of the Bulk Power System in North America" (May 2006), page 15. This reflects additions of power lines at 230 kV and higher voltage levels, based on circuit miles added.

²⁶ EIA, Annual Energy Outlook 2007, page 36.

²⁷ The U.S. government has recently estimated that average "residential electricity prices are projected to increase by 2.5 percent in 2007 and by a slightly lower rate of 2.0 percent in 2008, slightly lower than the rate of inflation." EIA, Short Term Energy Outlook – September 2007, page 5. These projections are tied in large part to expected prices for fossil fuel prices, which are expected to remain high in the near term or longer term EIA, Annual Energy Outlook 2007, pages 4-6.

²⁸ EIA's Annual Energy Outlook (2007) "assumes that, for the purposes of long-term planning in the energy industries, costs will revert to the stable or slightly declining trend of the past 30 years." (page 36). Further, a "total of 258 gigawatts of new capacity is expected between 2006 and 2030, representing a total investment of approximately \$412 billion (2005 dollars). If construction costs were 5 to 10 percent higher than assumed in the reference case, the total investment over the period could increase by \$21 billion to \$41 billion." EIA, Annual Energy Outlook 2007, page 41.

²⁹ "All told, investment in the transmission system is projected to add more than 7,122 miles of new transmission through 2009, and nearly 12,484 miles added during the 2005-2014 time period....Averaging \$14 billion per year over the next 10 years, expected distribution investment is almost triple the size of projected transmission spending." Edison Electric Institute, "New Investments for Transmission and Distribution Systems Are Needed," September 2006.

³⁰ These are estimates of annual costs to comply with the Clean Air Interstate Rule, the Clean Air Mercury Rule, and the Clean Air Visibility Rule, parts of which begin to go into effect in 2010 with several compliance phases in the subsequent years. These annual costs compare to projected health benefits of approximately \$63 to \$72 billion in 2010 and \$91 to \$106 billion in 2015. (EPA, October 2005), http://www.epa.gov/airmarkets/progsregs/cair/docs/cair_camr_cavr.pdf, page 30.

³¹ EIA, International Energy Annual, 2005, Table H.1co2 World Carbon Dioxide Emissions from the Consumption and Flaring of Fossil Fuels, 1980-2005; EIA, Emissions of Greenhouse Gases In the U.S.2004, December 2005.

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³² Per-capita consumption of electricity among Americans increased by 13 percent from 1990 to 2003 (the most recent data available). (13242.8 kwh per person per year in 2003, as compared to 11687.2 kwh per person in 1990). Source: Basheda et. al., "Why are Electricity Prices Increasing?" 2007, Appendix A.

³³ See, for example, the recent paper by Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007). For my own particular views on this issue, see the National Regulatory Research Institute's ("NRRRI") Journal of Applied Regulation, NRRRI 30th Anniversary Edition 19976-2006, Volume 4, December 2006 (article on pages 45-47). See also, the separate comments of Linda G. Stuntz, John Rowe/Elizabeth Moler, presented to the FERC Conference on Competition in Wholesale Markets, Docket No. AD07-7-000, February 27, 2007.

³⁴ See for example Pennsylvania Electricity Competition Act, § 2802. Declaration of policy. <http://www.puc.state.pa.us/electric/pdf/HB1509P4282.pdf>

³⁵ Among the understandings that were part of the Electric Competition Act were that utilities ought to have the opportunity to earn a fair rate of return. Electricity Generation Customer Choice and Competition Act § 2804. Section 4.III. "... (C) The electric distribution utility is subject to significant increases in the rates of federal or state taxes or other significant changes in law or regulations that would not allow the utility to earn a fair rate of return. (d) The electric distribution utility is subject to significant increases in the unit rate of fuel for utility generation or the price of purchased power that are outside of the control of the utility and that would not allow the utility to earn a fair rate of return."

³⁶ This occurred for some customers in Ameren's service territory in Illinois.

³⁷ One demand-response provider company, Enernoc, indicated in 2006 that its customers for "total energy management" programs include a "who's who" of large industrial firms, commercial office buildings, educational, groceries, department stores, health care facilities, hospitality and other light industrial facilities. See http://www.ksg.harvard.edu/hepg/Papers/Healy_Demand_Response_0306.pdf

³⁸ Saying that power markets are not perfect is different from saying that they are fundamentally flawed. As observed by Paul Joskow of MIT in February 2007, "The markets in the Northeast and Midwest organized around an LMP model and managed by an Independent System Operator (ISO) now work very well in almost all dimensions. These markets are extremely competitive under almost all contingencies. The wise use of independent market monitors and thoughtful market power mitigation mechanisms have largely mitigated potential market power problems when the few remaining contingencies arise. No market is textbook perfectly competitive and it is unreasonable to set that goal as a standard for wholesale electricity markets to meet." Paul Joskow, Prepared Remarks before the FERC, Conference on Competition In Wholesale Power Markets, Docket No. AD07-7-000 (February 27, 2007).

³⁹ This list of suggestions is based on a variety of sources, including comments made by participants at FERC conferences on wholesale market performance. See, for example the comments of John Shelk of the Electric Power Supply Association (<http://www.ferc.gov/EventCalendar/Files/20070228110115-Shelk,%20EPSA.pdf>), William Massey of Covington & Burling (<http://www.ferc.gov/EventCalendar/Files/20070314144339-Massey,%20Covington%20&%20Burling.pdf>), John Rowe and Elizabeth Moler of Exelon (<http://www.ferc.gov/EventCalendar/Files/20070227090732-Moler%20and%20Rowe,%20Exelon.pdf>), and Paul Joskow of MIT (<http://www.ferc.gov/EventCalendar/Files/20070228090000-Joskow,%20MIT.pdf>). (All accessed August 25, 2007).

EXHIBIT 2.3

NARUC PROCUREMENT STUDY

2008



NARUC

**The National
Association
of Regulatory
Utility
Commissioners**

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

**Susan F. Tierney, Ph.D.
Todd Schatzki, Ph.D.
Analysis Group**

July 2008

**Funded By
The U.S. Department of Energy**

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

**Susan F. Tierney, Ph.D.
Todd Schatzki, Ph.D.
Analysis Group**

**Boston, Massachusetts
July 2008**

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

EXECUTIVE SUMMARY

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

Over the past two decades, electric distribution utilities¹ have increasingly relied on competitive procurements as a means to obtain power supply for their retail customers. In many states, regulators now rely on such procurements as an important tool to help ensure that utilities provide cost-effective retail services. Today, more than 40 percent of U.S. states (or jurisdictions)² have formal regulations or guidance that requires or encourages utilities to use competitive processes. Although the use of competitive procurements to obtain supply for retail customers is not new, many of the requirements affecting when and how competitive procurements are to be used have either been newly enacted or substantively revised in recent years.

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

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

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

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

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- ***The procurement process should be fair and objective.*** A fair and objective process can avoid intended or unintended biases that may prevent selection of the “best” alternatives. The integrity of such a process encourages the participation of third-party suppliers by providing them with confidence that their offers will be fairly considered on their merits. To achieve this goal, procurements must include appropriate safeguards to prevent undue preferential treatment of any offers, to ensure that procurements are implemented as designed, and to ensure that unforeseen circumstances are addressed in manner that is fair and fundamentally consistent with the competitive intent of the process.
- ***The procurement should be designed to encourage robust competitive offerings and creative proposals from market participants.*** To encourage a competitive response, market participants need to have: (1) confidence that their offers will be considered fairly and objectively; (2) assurance that their confidential information will be reasonably protected; and (3) access to adequate information about bidder requirements, product specifications, model contract terms, evaluation procedures, and other factors that would affect the resources they choose to offer.
- ***The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors.*** Selecting the “best” offer(s) requires first identifying appropriate evaluation criteria and then evaluating the offers objectively against them. Designing an effective evaluation process is inherently challenging when such evaluations require comparisons of an array of price and non-price factors. In particular, many of these non-price factors are quite complex to quantify and/or qualitative in nature. By contrast, procuring products that meet standardized specifications (such as full requirements service for standard-offer-service customers in states with retail choice) greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone.
- ***The procurement should be conducted in an efficient and timely manner.*** Procurements should avoid unnecessary administrative costs that may discourage market participants, create transaction costs that produce price premiums in supplier offers, and ultimately impose greater costs on ratepayers.
- ***When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.*** Regulators’ own actions can positively – and in some cases, negatively – affect the integrity of a competitive procurement process. Positive signals can arise, for example, by doing what is legally possible to protect the confidentiality of commercially sensitive information submitted through supply offers, by conducting regulatory reviews in a time frame that supports the “best” price terms in offers, and enforcing elements of the procurement design that enhance the overall fairness and objectivity of the process and the integrity of the procurement results.

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

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

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

Regulators in these traditionally regulated states face a complex array of important issues in the design of effective procurements. Table 2 (at the end of the Executive Summary) lists a series of important topics that regulators must consider when guiding utilities' use of procurements and their overall design (“architecture”) and

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implementation. This list is long, and the choices often involve important tradeoffs, as described in greater detail in this report. Table 3 (also at the end of the Executive Summary) looks at these same issues through a somewhat different lens by identifying a series of key questions for regulators to bear in mind as they consider whether and how competitive procurements are to be used by utilities in identifying incremental supplies for retail customers.

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

- Involvement on a third-party independent monitor (“IM”) and/or independent evaluator;
- Measures to increase the transparency of the procurement process to market participants and the public;
- Providing potential bidders with detailed information needed to prepare competitive bids;
- Utility codes of conduct⁴ to prohibit improper sharing of information that is valuable to utility affiliates in their construction of procurement offers and/or their competitiveness in other electricity markets; and

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

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

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

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

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

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

Procurements for all-requirements service introduce different issues and challenges from those described above. In many of the states with retail choice and where distribution

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

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

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

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

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

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

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Table 3		
Key Procurement Policy Issues – A Checklist for Regulators		
Threshold Question	Second Order Question	Observation:
<p>☑ Should the utility test the market for alternatives to building its own power plants?</p>	<p>➔ If so, does the commission require (formally) the utility to carry out a competitive procurement, encourage such procurements by providing specific guidelines or recommendations, or give the utility full discretion to do so?</p>	<p>Clarifying commission policy toward competitive procurement and making such policy statements easy to find in PUC websites may lower barriers to entry for independent suppliers seeking to participate in the state's market; on balance, this may serve to support a deeper response to any solicitations.</p>
<p>☑ What is the "product" that the utility should procure through competitive solicitations?</p>	<p>➔ Is the procurement designed to solicit narrowly or broadly defined products? That is, should the procurement solicit offers for any type of resources to meet given power supply needs, or limit offers to:</p> <ul style="list-style-type: none"> ○ Supply-side resources? ○ Resources using a particular technology (e.g., renewables) or particular fuel (e.g., coal)? ○ Resources providing a particular function in a supply portfolio (e.g., baseload v. peaking)? ○ Capacity resources? ○ Resources in a particular zone? ○ Resources from new facilities? ○ Products satisfying particular regulatory requirements (e.g., renewable energy credits)? 	<p>Procurements with more narrowly defined products will allow greater reliance on price and less reliance on other evaluative criteria, although it may limit the depth of the market response and the creativity of offers from market participants.</p> <p>The greater control the commission wishes to exert over the choice of attributes of the product being solicited (e.g., type of resource, location, fuel or technology type, function in the portfolio), the more the commission will likely need to encourage review of formal (or informal) utility long-range resource plans in advance of the resource procurement.</p>
<p>☑ Does the commission want to allow – or require – the utility to participate in the solicitation, either directly as a supplier proposing a resource relying upon regulated investment, or indirectly through a competitive affiliate?</p>	<p>➔ If so, what safeguards will the commission establish and enforce in order to prevent improper self-dealing to assure a fair and competitive solicitation, increase the opportunity for the best resource to be selected, and assure the market that there will be no improper preferential treatment of utility or affiliate offers (thus instilling confidence in the overall design of the competitive procurement)?</p> <p>➔ Whether or not the utility is allowed to or does participate in the solicitation, how will the commission ensure that the utility's evaluation is focused on decisions supporting lowest-cost, reliable service to customers, even where different resource choices may have different impacts on the utility's own real or perceived financial interests? For example,</p> <ul style="list-style-type: none"> ○ Implications for the utility's risk profile, capital costs, balance sheet, and so forth, associated with of a third-party contract versus investment a utility owned plant? ○ Implications for the performance of the utility's own plants (e.g., implications for stranded investment) from transmission congestion due to new resource additions? <p>➔ What guidance will the commission provide to the utility and to market participants about how various risks should be assigned in contracts between:</p> <ul style="list-style-type: none"> ○ The utility (as buyer) and a third party supplier, and in turn between the utility and its retail customers; ○ The utility as a power plant owner and its customers. 	<p>Putting in place appropriate safeguards to ensure that the utility's decisions are made with the interests of customer benefits and costs in mind involves great care in the overall design, implementation and supervision of the procurement. Key safeguards to guard against improper self-dealing include:</p> <ul style="list-style-type: none"> ▪ Use of an independent monitor throughout all phases of the process; ▪ Commission review of product definition, evaluation assumptions and techniques, contract terms and conditions, debt-equivalency issues in rate cases (not RFPs) and other elements to support fairness for market participants; ▪ Requiring comparable forms of risk mitigation in utility and non-utility offers, such as comparable treatment of offer "refreshing" and various types of risk, including development and construction risk, power plant performance risk, fuel price risk, and risks tied to changes in law or regulation, such as costs of mitigating carbon emissions.

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Table 3 (Continued)		
Threshold Question	Second Order Question	Observation:
<p>☑ To what extent will winning resources be selected on price terms and non-price characteristics, some of which may be difficult to quantify and compare?</p>	<p>➔ How will the commission's policies shape how and what types of non-price characteristics should be considered by the utility in evaluating offers, in light of such criteria as:</p> <ul style="list-style-type: none"> ○ The potential differences in the importance of various non-price characteristics in alternative offers; ○ The potential for evaluation of non-price characteristics to impose high administrative costs or slow evaluation procedures; ○ The potential introduction of subjectivity (with the opportunity for self-dealing) that non-price characteristics may create? <p>➔ If non-price factors are necessary to the selection of "best" resources, how will the commission encourage a process that provides sufficient information to the market (e.g., what factors matter, what weight will be assigned to them, and how they will be measured) without also limiting the utility's flexibility to use qualitative judgment in evaluating offers? For example,</p> <ul style="list-style-type: none"> ○ Where the winning offers will become part of the utility's resource mix and have network service, how will the need for transmission additions be evaluated, particularly if impacts differ substantially among offers and take time and other resources to fully evaluate? ○ How will the utility take into account the development status (e.g., types of permits in hand, construction completed) of resource options in ways that support competitive responses while fully accounting for significant differences in risks to consumers? ○ How will the process incorporate any non-price factors that are relatively easy to put into dollar terms (e.g., transmission enhancement costs), and those (such as project development risk) which are harder to monetize? 	<p>The more transparent the evaluation procedures and criteria are to market participants, the more likely they will be assured that the evaluation process will be fair and objective. At the same time, the more the choice of "best resource" depends upon each offer's interaction with the rest of the utility's portfolio, the more the selection will depend upon complex modeling of the utility's portfolio; reliance on these models raises traditional transparency issues associated with "black box" modeling. As a result, regulators will need to pay attention to the modeling assumptions and inputs used by the utility in evaluating resource options (including sensitivity analyses) to help ensure a competitive result. Such review is particularly important where the utility (directly or indirectly) has a financial interest in the outcome of the results (e.g., either directly, if proposing a competing project, or more indirectly, if it owns another existing plant that may become less valuable depending on facility selection).</p>
<p>☑ If you have committed to having your regulated utilities use competitive procurement processes, are you willing to align your own regulatory practices to support them?</p>	<p>➔ Assuming that markets assign risk to uncertain regulatory outcomes, how will the commission arrange – and commit to implementing and enforcing – its own actions to support outcomes that appropriately balance risks between suppliers, the utility and ratepayers? Relevant regulatory risks that can show up in price premiums include:</p> <ul style="list-style-type: none"> ○ Uncertainty about cost-recovery for utilities' contracts with power suppliers versus the utility's own investment; ○ Uncertainty about how long contract approval will take; ○ Uncertainty about whether the regulator will enforce the rules requiring fairness and objective processes; ○ Uncertainty about whether the commission will reopen the process – or throw out the results – if it doesn't like the particular outcome of a solicitation; and ○ Uncertainty about whether the regulator will allow the utility to take actions that circumvent the procurement, alter procurement procedures mid-stream, or dissolve the procurement (irrespective of rationale)? 	<p>The higher the market's confidence that the regulatory agency will support its own past policies and decisions, the lower the risk premium that will be built into offers from the market. Past commission policies and decisions may include meeting certain procedural time requirements to which it has committed and enforcing as appropriate any procurement rules previously adopted.</p>

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COMPETITIVE PROCUREMENTS OF RETAIL ELECTRICITY SUPPLY

I. INTRODUCTION AND BACKGROUND

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

Despite this long experience, the use and regulation of competitive procurements has undergone important changes in recent years. Today, many states require⁶ – directly or indirectly – that their utilities use competitive procurements as a means of obtaining supplies to serve their retail customers. All told, more than 40 percent of the U.S. states (or jurisdictions)⁷ have formal regulations or guidance that requires or encourages utilities to use competitive processes.

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

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

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

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

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

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power procurement. As part of this collaborative dialogue, NARUC engaged Analysis Group⁸ to perform a study of competitive procurement of retail electric supply.⁹

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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II. OVERVIEW OF STATE COMPETITIVE PROCUREMENTS

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

Table 4				
Frameworks for Procurement of Electricity Supply for Retail Customers				
Electric Industry Structure	Divestiture of Power Plants	Procurement Framework / Product Solicited	Supply Portfolio Management	State Examples
Traditional	None	Incremental Supply – typically for resources from a specific power plant obtained through requests for proposals (“RFPs”)	Utility	CO, GA, LA, OK
Restructured, No Retail Choice	None or Partial	Incremental Supply (via RFP)	Utility	CA, MT
Restructured, Retail Choice	Full (or near full)	Full Requirements Service (“FRS”) (via auctions or RFPs)	Market	MA, MD, ME, NJ
		Hybrid FRS Frameworks: <ul style="list-style-type: none"> • Long-term contracts (with FRS procurement) • Utility ownership of generation, with some degree of portfolio management by the utility • Public power authority • Specialized procurements (e.g., renewables or renewable energy credits) 	Variously Assigned to Market and to Utility	CT, DE, IL, OH, PA

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

Some traditionally structured states (such as Colorado, Georgia, Louisiana, and Oklahoma) have adopted relatively explicit regulations or formal guidance addressing

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

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

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

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

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

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

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

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

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

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

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

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

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

III. CRITERIA FOR THE EVALUATION OF COMPETITIVE PROCUREMENTS

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

Table 5 Criteria for evaluating competitive procurements for retail supply:
Where regulators have committed to relying upon competitive procurement approaches as a means to help identify the “best” resources needed to meet the needs of the utility’s customers, the process should have and be viewed as being: <ul style="list-style-type: none">• Fair and objective;• Encouraging of a robust competitive response and creative proposals from market participants;• Based on appropriate and relevant evaluation of price and non-price factors;• Efficient and timely in offer selection;• Positively supported by regulatory actions that reinforce the commission’s commitment to the other criteria.

- ***The procurement process should be fair and objective.*** A fair and objective process will help to ensure that the outcome of a procurement “best” satisfies retail customers’ supply requirements and does not reflect any undue preferential treatment of particular bidders. Such a process also promotes participation by assuring market participants that their offers will be fairly considered on their merits. To achieve this goal, procurements must include appropriate safeguards built into the design of the procurement to prevent undue preferential treatment of any offers. These safeguards must be supported through the practical elements of the implementation phase so that unforeseen circumstances are addressed in manner that is fair and consistent with a competitive outcome. The fairness and integrity of a procurement process is affected not only by the actions of the utility, but also by regulatory oversight of the procurement process. If a commission decides to rely on competitive processes, its own actions to enforce fundamental fairness objectives and uphold any prior commitments to use markets are a critical component of the process of identifying the “best” retail supply for utility customers.
- ***The procurement should be designed to encourage a robust competitive response and creative offerings from market participants.*** In developing a competitive procurement, the regulators’ goal is to design and carry out a process in which suppliers of the most cost-effective resources not only participate but also submit their most competitive offers. Several conditions are key to encouraging such participation. First, market participants must perceive that their offers will be

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considered fairly and objectively. Concerns about preferential treatment will lower market participants' willingness to incur the up-front costs necessary to submit offers. Second, procurements must protect confidential and commercially sensitive information submitted by market participants. Third, market participants must have access to adequate information about bidder requirements, product specifications, model contract terms, evaluation and selection procedures and criteria, and other factors that would affect the resources they choose to offer. Finally, procurements should allow sufficient creativity to solicit the best offer for customers.

- ***The procurement should select winning offers based on appropriate evaluation of all relevant price and non-price factors.*** Selecting the "best" offer(s) requires first identifying appropriate evaluation criteria and then evaluating the offers objectively against them. Designing an effective evaluation process is inherently challenging when such evaluations require comparisons of an array of price and non-price factors. In particular, many of these non-price factors are quite complex to quantify and/or qualitative in nature. By contrast, procuring products that meet standardized specifications (such as full requirements service for standard-offer-service customers) greatly simplifies the evaluation process by allowing for the selection of winning offers based on price terms alone. Identifying evaluation criteria that reflect the attributes of greatest importance will increase the likelihood of eliciting offers that best suit retail customers' supply needs.
- ***The procurement should be conducted in an efficient and timely manner.*** Competitive procurements should avoid unnecessary administrative and procedural costs that may discourage market participants and ultimately impose greater costs on ratepayers. Because bidders are generally required to honor the terms of their offers once made, an unnecessarily slow process increases the financial risks they face from unanticipated changes in market conditions that occur while their offers are "open." Design of bid submission requirements, evaluation and selection procedures, and the timing of commission review should aim to minimize transaction costs for utilities and/or bidders (and the price premiums they include in their bids).
- ***When using a competitive procurement process, regulators should align their own procedures and actions to support the development of a competitive response.*** Regulators' own actions can positively – and in some cases, negatively – affect the integrity and outcomes of a procurement process. Positive signals can arise, for example, by doing what is legally possible to protect the confidentiality of commercially sensitive information submitted through supply offers, by conducting regulatory reviews in a time frame that supports the "best" price terms in offers, and enforcing elements of the procurement design that enhance the overall fairness and objectivity of the process and the integrity of the procurement results.

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

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of a competitive process will provide confidence that the process will be fair and objective; this in turn will increase the likelihood that there will be a competitive response from the market and that the winner of the process will be the “best” resource for customers.

VI. PROCUREMENT OF INCREMENTAL RESOURCES

A. OVERVIEW

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

In states with a more traditional industry structure, utilities provide bundled electricity service as the sole option for retail customers. The utility has the responsibility to manage a resource portfolio, which typically¹⁹ includes large amounts of generation assets under its ownership, but may also include short- and long-term purchase power agreements, demand-management resources, and other forms of financial hedges and supplies. The extent to which these utilities actually use competitive procurements when seeking to identify and secure the next new resource(s) to add to the resource portfolio varies across and within states.

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

- the physical characteristics of the resources used to provide supply (e.g., location; technology type; fuel type; availability factors; start-up, ramp rates and cycling features; maintenance requirements);
- operational commitments (e.g., dispatchability or non-dispatchability; provision of energy, capacity, ancillary services, or environmental attributes; plant operation, management and fuel provision by the utility under a "tolling agreement"); and
- development status (e.g., site control; environmental permits; interconnection studies; financing; construction).

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

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

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- structure of payments (e.g., all-in prices versus separate payments for such things as energy, capacity, ancillary services; fixed prices versus indexed prices; allowances for payment adders in the event of changed circumstances; penalties and bonuses for certain performance targets (such as delay in meeting development milestones or availability targets);
- the service provided (e.g., energy; capacity; unit dispatch control, in which the utility has control over when the resource delivers power; tolling agreements, in which the utility operates and manages the plant and controls the fuel supply as well; extra compensation for “regulation” service, allowing the output of the plant to be controlled by the system control area operator or system dispatcher; provision of “environmental attributes” such as renewable credits);
- supplier obligations, such as purchase requirements (e.g., minimum quantities of energy over a specified time period, or take-or-pay provisions) and fuel cost requirements (e.g., e.g., tolling agreements in which the utility provides the fuel, or the supplier has responsibility for fuel); and
- the resulting allocation of risks borne by suppliers and utilities.

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

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

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

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

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

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

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

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

B. RECENT STATE POLICIES ADDRESSING DESIGN OF COMPETITIVE PROCUREMENTS

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

C. PROCUREMENT PROCESS ARCHITECTURE

1. *Introduction to Procurement Design*

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

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

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

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

Table 6			
Recent Changes in State Policy Requirements Involving Competitive Procurements for Incremental Resources			
State	Date	Docket Name	Description
AZ	2007	Recommended Best Practices for Procurement (ACC Decision No. 70032)	Commission adoption of "Best Practices" for procurements that identify acceptable procurement methods, and circumstances when RFPs and independent monitor should be used [1]
CA	2003 - present	Energy Action Plan, PUC Decision 04-01-050, AB57 and various other rulings	A series of legislative and commission decisions have established procedures by which utilities develop long-term procurement plans and implement resource procurements.
FL	2002	Rule 25-22.082 Amended	Amendment to rules requiring competitive procurements for approval of utility self-build proposals, including procedures regarding bid-refreshing and information requirements regarding the self-build offer and evaluation process.
GA	2004	Amendment to Georgia Code 515-3-4-.04 Identification of Capacity Resources	Georgia General Assembly revision to the IRP Act, to include competitive procurement rules, including requirements for independent monitors
LA	2004	Market Based Mechanism Order (General Order, Docket No. R-26172 Sub Docket A)	Requirement that utilities use an RFP process to acquire and justify new resource acquisitions, including requirements for independent monitors and providing information to the public in advance of procurements
OK	2007	Title OCC, Subchapter 35: Electric Utilities – Amendments, Competitive Procurements	Specific requirements for competitive procurements necessary for filling new resource needs, including use of independent monitors and requirements related to affiliate bids and evaluation processes
OR	2006	PUC Order No. 06-446	Update of prior order providing guidelines for competitive procurements, including 13 guidelines for RFP design, bid evaluation and selection, role of an independent evaluator, treatment of self-build and affiliate offers, and other elements
UT	2005	Utah Energy Resource Procurement Act Statute (Title 54, Chapter 17)	Requirements for procurement process for new energy resources, including requirements for an independent monitor
UT	2007	Rules R746-420, R746-430, R746-440	Rules refining requirements for competitive procurements mandated in Title 54, Chapter 17 (2005)
WA	2003	General Order No. R-509	Requirements that utilities solicit supply offers, including: specifications for RFP contents, bid ranking, and contracts; bidder option to request an independent monitor to assist commission review if the utility or its affiliates participate as bidders.
[1] A formal rulemaking process has not been undertaken. Some investor-owned utilities are subject to specific procurement requirements arising from restructuring settlement agreement.			

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

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

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

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

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

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

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

Box 1

Incremental Supply Procurement Process in Georgia

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

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

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

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

^a Amendments to Georgia Code 515-3-4-.04, Identification of Capacity Resources.

^b GA PSC Order, 15392-U, December 2002.

^c Accion Group, Report to the Georgia Public Service Commission on the Georgia Power Company 2009 RFP, p.31.

2. *Resource Plans and Related Issues Preceding Procurements*

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

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

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

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

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

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

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

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

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

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

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

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

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

Box 2

Dealing with capital-intensive, new and untested technologies

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

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

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

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

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

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

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

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

a. *Independent Monitor*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

b. Public (or Stakeholder) Participation

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

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

c. Utility Codes of Conduct

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

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

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

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

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

4. *Design/Structure of the Evaluation Process*

a. *Evaluation Timing*

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

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

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

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

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

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

b. Contract Negotiation, Including Model Agreements and Bid Refreshing

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

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

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

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

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

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

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

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

5. *Commission Reviews of Procurement Process and Results*

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

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

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

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

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

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

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

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

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

1. *Overview*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

3. *Economic and Financial Risks*

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

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

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

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

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

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

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

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

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

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

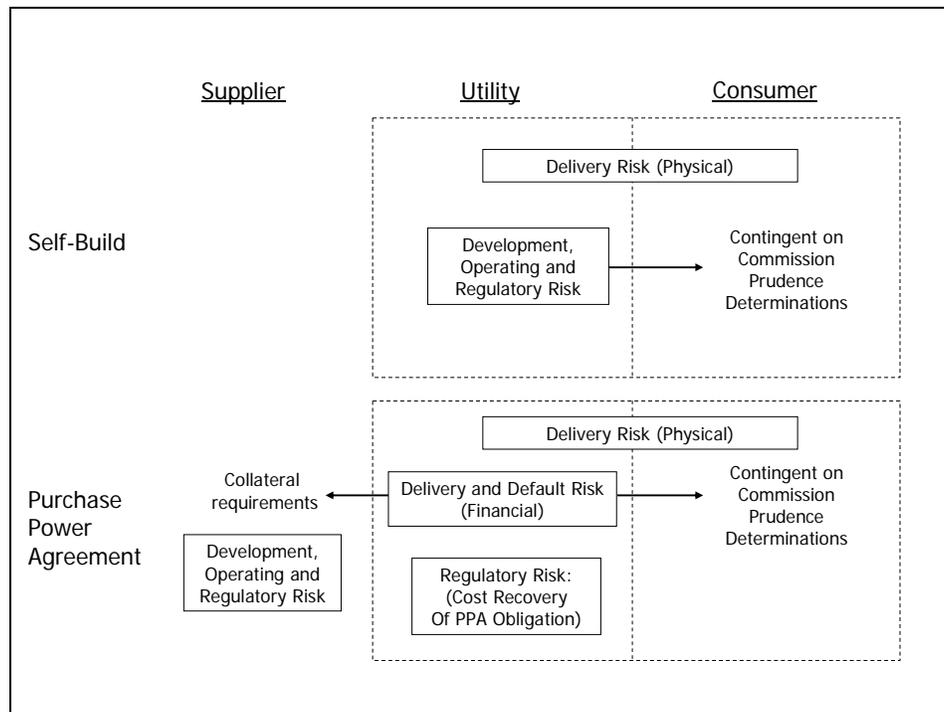
How these risks are allocated between third-party suppliers, the utility (as buyer in a PPA or as a power plant owner) and retail customers is a fundamental issue for utilities and regulators relying upon competitive procurements. Table 7 shows how the terms of PPAs can shift various project risks away from the utility (and its retail customers) to

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suppliers, as compared to utility self-build. With a self-build, these risks are distributed between utilities and customers depending on commission rulings.⁵⁰ By contrast, at the other end of the spectrum are PPAs. These agreements shift many of these risks to suppliers, by requiring, for example, that they deliver replacement power at a certain price even if fuel prices increase or pay other penalties if the plant performs poorly. Other types of agreements, such as those presented in Table 7, shift certain pieces of these financial risks.

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

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



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

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

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

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

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

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

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

4. *Credit*

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

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

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

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

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

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

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

- *Collateral requirements during procurement.* To ensure that suppliers' offers are sufficiently developed and financially credible, some utilities require bid deposits when offers are initially submitted, and/or require financial guarantees of the offers chosen for the "short-list" of considered offers. However, such requirements may act as a barrier to entry for smaller and less-well-financed suppliers, which may be a particular constraint in some procurements, such as those for renewable resources.⁵⁴ As a result of this trade-off, regulators and utilities should carefully consider the likelihood that non-bona-fide offers will be a problem, as regulators/utilities determine whether and what kind of bid deposits and other financial guarantees to require in the initial stages of offer submission and review.
- *Collateral requirements over the contract life-cycle.* The level of financial guarantee necessary to address delivery risk varies over the project's life-cycle, with different risks associated with bid selection, development and operation stages. PPAs should appropriately address these changing realities over the course of the supply agreement.
- *Flexibility in the means of fulfilling collateral requirements.* To minimize the cost to suppliers of providing collateral, utilities can provide suppliers with alternative means of fulfilling these requirements. In addition to letters of credit, financial guaranties from credit-worthy entities, and cash, the utility may consider other forms of guarantee, including second liens, claims to plant warranties or insurance policies, or step-in rights, in which the utility can take-over project development in the event of developer default.⁵⁵

5. *Debt Equivalency*⁵⁶

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

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

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

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

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

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

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

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

In general, regulatory decisions about how best to adjust any inferred debt are complicated by the less-than-complete empirical evidence available on the financial risks associated with PPAs versus other means of supply. To date, there is relatively little research that has assessed how alternative means of fulfilling resource needs impact a

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utility's overall cost of debt or return on equity.⁵⁷ In fact, there is even uncertainty regarding how PPAs impact the credit ratings developed by credit-rating agencies. While certain credit agencies have clearly described certain quantitative balance sheet adjustments made for PPAs, they also note that these are only one among many possible adjustments that may affect a utility's credit rating.⁵⁸ However, because many of these other considerations are less clearly described and are more qualitative in nature, determining a PPA's net impact on utility credit ratings is difficult. These considerations again caution against assessment of debt equivalency, or any risk factor, outside of a comprehensive evaluation that accounts for all of the various risks posed by alternative utility obligations and commitments from the standpoint of consumers, while leaving the utility fairly compensated for its financial risks. These issues are normally addressed by commissions in general rate cases in which regulators examine the capital structure and cost of capital of the utilities they regulate.

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

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

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

⁵⁹ For example, Colorado, Florida, and Wisconsin.

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

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

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

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

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

6. *Economic Risk Mitigation Aspects of PPAs*

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

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

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

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

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

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

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

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

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

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

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

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

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

7. *Transmission*

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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- ***Bidder assumptions about who pays for system integration costs for winning offers*** – In theory, the transmission-related costs associated with individual offers can be borne by either the bidder or the utility soliciting the offers. Most utility procurements require that bidders assume in their offers that they will absorb the costs to interconnect their facilities to the grid. But procurements for incremental resources have varied with regard to assumptions about for transmission upgrades needed to integrate the facility into the system. On the one hand, there are instances where procurements have required that bidders assume that they will directly have to absorb the costs of any incremental system upgrades associated with its project; in these instances, a reasonable bidder will construct a bid that allows for recovery of such costs as part of the purchase of power from the project. Other competitive procurements have incorporated a different assumption – that is, as long as a bidder’s resource is located in or delivered into the utility’s service area, the bidder should assume that it will not have to directly absorb system integration costs if the bidder’s project is selected by the utility.⁷⁵ These two approaches can introduce quite different assumptions into the price of power supply bids. In the former type of bid, on-system transmission integration costs may be built into generation prices; in the latter, generation offer prices do not incorporate system integration costs and differences in transmission-cost implications of alternative offers are accounted for in the utility’s evaluation of those offers. In the end, either way approach leads to a result in which the transmission costs associated with winning (and approved) offers will inevitably be born by consumers, whether it is through inclusion of such costs in suppliers’ bids or through distribution utilities’ charges to their retail customers to support transmission investment needed to deliver power to them. However, the size of these costs may not be the same under both circumstances. For example, suppliers facing the requirement that they pay for transmission system impacts, but with limited information useful to determining such costs, may add price premiums to their offers to account for such uncertainty.
- ***Transmission study timeliness and cost*** – Because transmission system planning studies can be time consuming, expensive and otherwise resource-intensive,⁷⁶ these studies have the potential to create a bottleneck in evaluation

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

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

⁷⁶ The cost and time of a full system impact study may place real constraints on how these studies are used in the evaluation stage of a competitive procurement process. Most procurements rely upon a preliminary

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

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

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

The complexity of these various transmission-related issues suggests that competitive procurements should include clear ground rules about the transmission-related

transmission analysis for early stages of the evaluation process, both to lower the cost the evaluation and complete these initial assessments in a timely fashion. Once the initial evaluation stage has identified a short-list of the most competitive bids, full system impacts studies are then performed for bids on this short-list. For example, see the Georgia Power 2009 RFP (Accion Group, "Report to the Georgia Public Service Commission on the Georgia Power Company 2009 RFP," p. 27.) Also, the Entergy Louisiana Little Gypsy 3 procurement (Potomac Economics, "Independent Monitoring of the Evaluation of Proposals for Entergy Long-term Supply-side Resources, Solid Fuel Final Report," September 2007).

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

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

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

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assumptions to be used in preparing all bids and evaluating all offers (including self-build proposals). As a result of the complexity of these transmission issues, oversight by independent monitors may be important to ensuring bidder confidence and enforcement of procurement rules.

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

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

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

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

For offers meeting these eligibility requirements, the further assessment of non-monetized criteria can take many forms. These assessments may range from evaluations that explicitly score and weight identified criteria to those that simply list non-monetized criteria that will be considered by the utility using their discretion. These alternatives balance several factors. Explicit scoring and weighting provides transparency to bidders, independent monitors and commissions, but may lead to evaluations that constrain the utility’s ability to exercise appropriate judgment about these non-monetized criteria. Choices made by firms every day reflect these types of judgments about non-monetized factors, similar to the types of judgments made by homeowners when choosing a construction contractor. While procurements that simply

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identify relevant non-monetized criteria provide evaluators with flexibility in how such factors are considered, however, they may provide the utility with a subtle and difficult-to-trace way to exert improper preferential treatment for or against certain supplies. For example, in some circumstances, bids have been eliminated in the initial review or short-list stage due to concerns about the viability of the resource given information on: project schedules; engineering, finance and permitting status; credit-worthiness; and other considerations.⁸⁰ In particular where utility self-build proposals or affiliate offers are involved, regulators should scrutinize the use of non-monetized criteria and expect to rely on on-the-ground oversight from an independent monitor to help ensure that such criteria are not used to improperly exclude certain offers from consideration.

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

VI. PROCUREMENT OF FULL REQUIREMENT SERVICE

A. OVERVIEW OF FRS SUPPLY PROCUREMENTS

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

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

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

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

Box 3

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Box 4

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

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

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

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

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

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

As a result of these competing goals and particular customer attributes, regulators and utilities often design standard-offer products – and the procurement of supply for them – to meet the different needs of different customer classes. Products for residential and small commercial customers are typically designed to minimize price variation through use of overlapping, two- to three-year contracts with fixed prices. By contrast, products for larger customers (i.e., customers above some pre-determined load threshold)

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generally follow market prices through single, short-duration (e.g., three-month) contracts with prices that vary by month or hour. Regulators appear more willing to shield smaller customers from market volatility given the fewer number of competitive suppliers available to them and, potentially, other policy concerns. Appendix E provides examples of different types of FRS products currently being procured in different states.

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

C. PROCUREMENT APPROACH – AUCTION AND REQUESTS FOR PROPOSALS

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

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

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

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

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

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

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

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

D. OTHER ELEMENTS OF FULL REQUIREMENTS SERVICE DESIGN

1. *Bidder Eligibility and Collateral Requirements*

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

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

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

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

⁹¹ Competitive Procurement Survey Response from Massachusetts.

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

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

2. *Independent Monitors*⁹³

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

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

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

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

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

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

3. *Timing and Commission Approvals*

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

4. *Confidentiality*

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

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

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

⁹⁶ For example, Maine and Massachusetts.

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

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

VII. CONCLUSION

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

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

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

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

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

APPENDIX A – INDEPENDENT MONITOR ACTIVITIES AND ROLES

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

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

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

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

¹⁰⁰ Utah Administrative Code, R746-420.

¹⁰¹ Utah Administrative Code, R746-420.

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

APPENDIX B – CREDIT REQUIREMENTS

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

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

THE LEVEL OF GUARANTY OR COLLATERAL REQUIREMENTS

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

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

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

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

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

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

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

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

MEANS OF REDUCING THE COST OF CREDIT REQUIREMENTS

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

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

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

¹⁰⁶ KEMA, 2006, p. 6.

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

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

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

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

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

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

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Table B1 – Credit Requirements From Selected Procurements			
RFP	Timing of Credit Requirements (after short-list; during construction; during operation)	Allowed Forms of Credit	Credit Requirement Amount
Southern California Edison 2006 RFO (All Source)	<ul style="list-style-type: none"> • Development security from effective date (regulatory and contract approvals) to beginning of delivery • Delivery security 	Unspecified	<ul style="list-style-type: none"> • Development security of \$109.6/kW (fast track) and \$54.8/kW (standard track) • Delivery security required for amounts above unsecured credit to cover mark-to-market exposure over a 24- or 48-month period. (Only investment grade bidders eligible for unsecured credit.) • Seller grants secondary liens to SCE
Pacific Gas & Electric 2005 (New Generation Resources)	<ul style="list-style-type: none"> • Proposal fee • Selection security (upon request for CPUC approval) • Development security • Operating security 	Unspecified	<ul style="list-style-type: none"> • Proposal fee: \$5/kW • Selection security: \$10/ kW • Development security: \$61/ kW • Operation security: mark-to-market (either a 2- or 5-year window, depending on time to replace generation), and collateral threshold
Georgia Power Company and Savannah Electric Company 2009 RFP	Unspecified, but ability to meet credit standards or security requirements must be demonstrated in offer	<p>Credit requirements may be met through:</p> <ol style="list-style-type: none"> 1) Seller net worth threshold; 2) Guaranty from entity meeting net worth threshold; 3) Investment grade credit rating based on utility evaluation; or 4) Collateral sufficient to cover potential damages resulting from seller default (levels are not specified). <p>Unless a successful bidder (or its guarantor) is rated at least one notch above investment grade, then 50% of such bidder's security collateral must be in the form of cash or a letter of credit.</p>	Credit requirements standards can be met through either demonstration of credit-worthiness (with specific Allowed Forms of Credit) or posting of collateral sufficient to cover necessary damages resulting from default
Progress Energy Florida (2003)	<ul style="list-style-type: none"> • Development security starting 30 days after contract signing • Operating security starting 30 days prior to planned operation date for the duration of the contract 	Letter of credit, cash, or U.S. bonds held in escrow	<ul style="list-style-type: none"> • Development security starting at \$20/ kW and rising to \$50/kW (at 12 months before commercial operation) • Initial operation security of \$10/kW, \$20/kW after 5 years, and \$30/kW after 10 years

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Table B1 – Credit Requirements From Selected Procurements			
RFP	Timing of Credit Requirements (after short-list; during construction; during operation)	Allowed Forms of Credit	Credit Requirement Amount
Entergy 2006 RFP for Long-Term Supply-Side Resources	<ul style="list-style-type: none"> Letter of intent security Performance collateral upon execution of agreement 	<ul style="list-style-type: none"> Traditional forms of collateral and non-traditional forms on a case-by-case basis (e.g., lien on assets and step-in rights) 	<ul style="list-style-type: none"> Letter of intent security of \$2 million Performance collateral: \$200 per kW for solid fuel; \$100 per kW for CCGT Entergy determines amount of uncollateralized exposure based on the bidder's credit rating (up to \$100 million for AAA to A-)
Northwestern Energy (Issued July 2, 2004)	Unspecified	<ul style="list-style-type: none"> Demonstration of investment grade credit rating Acceptable performance assurance, including letter of credit, guaranty from parent company, or cash 	Unspecified
PacifiCorp's 2012 RFP	Security starting on the date of PUC contract approval or execution by parties (starting at 10% of full credit and rising to 100% in 2 years, with full credit due when financing secured)	<ul style="list-style-type: none"> On-going: letters of credit, guaranties, cash or other collateral Asset-back agreements "must" backup agreement with the resource through certain options, including step-in rights, second lien, leverage limitations, and other financial covenants Initial (10%) security must be posted with letter of credit or cash unless 100% of security is posted at effective date 	<ul style="list-style-type: none"> Credit requirements reflect PacifiCorp's market exposure given type of agreement, agreement term, and other factors Credit matrix identifies security requirement based on type of resource, size of resource, and the year the resource is expected to be operational PacifiCorp permits some uncollateralized supplier exposure depending on seller's credit rating and the type of resource
PacifiCorp's 2009 RFP	Security starting on the date of PUC contract approval or execution by parties (starting at 10% of full credit and rising to 100% in 2 years)	Acceptable "credit assurances" are unspecified (letter of credit is acceptable)	<ul style="list-style-type: none"> Credit matrix based on type of resource, size of resource, and the year the resource is expected to be operational PacifiCorp permits some uncollateralized supplier exposure depending on seller's credit rating and the type of resource
Puget Sound Energy 2008 All Source RFP	Unspecified	Unspecified	May be required to post collateral absent demonstration of credit-worthy status (BB+ or better) or guaranty from credit-worthy parent company

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Sources:

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

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

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

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

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

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

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

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

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

APPENDIX C – DEBT EQUIVALENCY

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

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

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

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

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

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

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

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

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

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

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

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

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APPENDIX D – EVALUATION OF PRICE AND NON-PRICE FACTORS

Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	State	RFP	Monetized	Non-monetized
[1]	UT	PacifiCorp 2009	Price, based on ratio of bid price to projected price (60%) ¹¹⁴ : (for a ratio of [x], the bid gets [y] points:) <ul style="list-style-type: none"> • Ratio < or = 80%: 100% • Ratio > 80%, but < 120%: 100% times ratio • Ratio > or = 120%: 0% 	Non-price factors will be weighted (40%): <ul style="list-style-type: none"> • Flexibility of resource dispatch: day-ahead and adjustment: 20%; or only day-ahead: 10% • Exceptions to any pro forma agreements: 10% • Environmental attributes relative to the resource, if applicable: 10%
[2]	OR	PacifiCorp 2012	Price, based on ratio of bid price to projected price (70%) ¹¹⁵ : <ul style="list-style-type: none"> • Ratio < or = to 80% of adjusted price curves: 100% • Ratio > 80%, but < 120%: 100% times ratio • Ratio > or = 120%: 0% 	Nonprice factors will be weighted (30%): <ul style="list-style-type: none"> • Development, construction, operational experience: 10%¹¹⁶ • Compliance with pro forma agreements submitted with proposal: 10%¹¹⁷ • Site control and permitting: 10%
[3]	OK	Oklahoma Gas & Electric Co. 2008-2010 RFP	Price factor (60%), reflecting: <ul style="list-style-type: none"> • Capacity charge • Energy charge • Start-up charge • Transmission system impact 	<ul style="list-style-type: none"> • Bidder's proposed changes to Model PPA: 10% • SPP RTO market risk cost allocation: 15%¹¹⁸ • Quality of output: 15% <ul style="list-style-type: none"> - Dispatchability/scheduling - Reliability/availability - Operating profile/characteristics

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

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

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

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

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

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Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	State	RFP	Monetized	Non-monetized
[4]	AZ	Arizona Public Service Commission 2007 RFP for Renewables	Quantitative ¹¹⁹ : Respondent Bid Price plus Additional Costs is compared against Market Cost of Comparable Conventional Generation ¹²⁰	<ul style="list-style-type: none"> • Financial risk • Regulatory risk • Counterparty credit risk • Transmission risk • Operations risk • Project development risk
[5]	MT	NWE 2004 RFP	Proposal price and value, including: <ul style="list-style-type: none"> • Costs/benefits of transmission • Value of dispatchability • Firmness of products • Ability to remarket energy • Value of points of delivery • Ancillary services value • Costs of resource integration 	<ul style="list-style-type: none"> • Development and performance risk (2nd most important factor) • Environmental factors (3rd most important factor)
[6]	FL	Progress Energy 2007 RFP	<ul style="list-style-type: none"> • All costs, as reflected in 30 year optimization analyses 	Minimum bidder eligibility requirements: <ul style="list-style-type: none"> • Environmental • Engineering and design • Fuel supply and transportation plan • Project financial viability • Project management plan Technical criteria: ¹²¹ <ul style="list-style-type: none"> • Development feasibility • Project value • Operational quality

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

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

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

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Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	State	RFP	Monetized	Non-monetized
[7]	WA	Puget Sound Energy (PSE)	<ul style="list-style-type: none"> • Resource cost • Transmission • Portfolio cost impact¹²² • Capital structure impacts • Guarantees and security¹²³ 	<ul style="list-style-type: none"> • Timing • Resource match to monthly need • Operational flexibility • Performance within utility's own resource mix/portfolio • Status and schedule • Price volatility • Resource flexibility and stability • Resource technology • Long-term flexibility • Project risk • Impact on PSE's overall risk¹²⁴ • Environmental & permitting risk • Ability to deliver as proposed • Status of transmission right • Managerial control • Security & control • Federal regulatory approvals • Environmental impacts • Resource location • Community impacts • Future exposure to taxes and/or environmental regulation
[8]	LA	Entergy Fall 2006 RFP	Individual and portfolio costs, as estimated by a production cost model	<p>Non-quantifiable aspects of:</p> <ul style="list-style-type: none"> • Transmission • Fuel cost and availability <p>Portfolio design criteria, including:</p> <ul style="list-style-type: none"> • Product category supply cost ranking • Maximum total resource objective • Regional dispersion • Product category needs • Mix of product terms

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

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

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

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Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	State	RFP	Monetized	Non-monetized
[9]	GA	Georgia Power Company and Savannah Electric 2009 RFP	<p>Fixed costs:</p> <ul style="list-style-type: none"> • Capacity cost payment • Fixed O&M payment • Cost due to inferred debt from PPA¹²⁵ • Startup costs • Fuel pipeline costs, including the estimated costs for adequate firm natural gas transportation and natural gas storage <p>Variable generation costs:</p> <ul style="list-style-type: none"> • Fuel cost • Variable O&M • Proposal dispatch characteristics <p>Transmission costs:</p> <ul style="list-style-type: none"> • Integration costs • The increase (or decrease) in transmission system energy losses 	<p>Development schedule:</p> <ul style="list-style-type: none"> • Reasonableness • Contingencies • Current developmental status <p>Resource schedule and dispatch flexibility:</p> <ul style="list-style-type: none"> • Lead time for dispatch schedules¹²⁶ • Ability to change schedules hourly/daily¹²¹ • Quick start capability or curtailment • Minimum schedule and downtime • Minimum energy take¹²¹ • Response to emergencies • Dispatchability¹²¹ • AGC capability <p>Fuel:</p> <ul style="list-style-type: none"> • Type of fuel • Risk of fuel supply interruption • Price risk <p>Environmental:</p> <ul style="list-style-type: none"> • NOx, VOC and SO² compliance strategy • Toxic release inventory • Future permitting restrictions • Water requirements <p>Proposed PPA changes</p> <p>Transmission:</p> <ul style="list-style-type: none"> • Impact on transmission interface capability¹²¹ • Transmission delivery risk¹²¹ • Voltage control¹²¹ • Other grid impacts¹²¹

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

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

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Illustrative Examples – Ways that Different Utilities Have Addressed Various Price and Non-Price Factors, and Whether These Factors Have been Monetized				
Source	State	RFP	Monetized	Non-monetized
[10]	CA	Southern California Edison 2006 RFO	<ul style="list-style-type: none"> • Market assessment: the market value of the benefits contained in each offer versus its costs¹²⁷ • Transmission impact: cost of network upgrades • Debt equivalence as additional cost • Environmental: greenhouse gas emissions adder (\$8 per ton of CO²) • Credit: ability to post collateral if necessary 	<ul style="list-style-type: none"> • Ability to fill capacity requirements • Portfolio fit: impact the offer has on (i) the demand and supply effect on CAISO zone and (ii) the ability of SCE's portfolio to meet SCE's RAR¹²⁸ • Project viability: ensure project can be constructed consistent with terms of RFO • Physical concentration risk¹²⁹ • Financial concentration risk

Sources:

- [1] PacifiCorp 2009 RFP Flexible Resources, September 2005, pp. 26-38.
- [2] PacifiCorp 2012 RFP Base Load Resources, April 5, 2007, pp. 30-35.
- [3] Oklahoma Gas & Electric Company, RFP for Capacity and Energy Resources Years 2008-2010, Issued March 29, 2007, pp. 13-17.
- [4] Arizona Public Service Commission 2007 RFP for Renewable Resources, March 5, 2007, pp. 8-11.
- [5] Puget Sound Energy, RFP for All Generation Resources, January 2008, Exhibit B; and Puget Sound Energy, 2006 RFP for Long-Term Supply Side Resources, p. F-4.
- [6] Progress Energy Petition for Determination of Need of Hines 4 Combined Cycle Unit, August 4, 2004, pp. 50-66.
- [7] Northwestern Energy RFP issued July 2, 2004, pp. 6-8.
- [8] Entergy Fall 2006 RFP for Limited-Term Supply-Side Resources, October 24, 2006, Appendix E.
- [9] Georgia Power Company and Savannah Electric and Power Company 2009 RFP, July 5, 2005, pp. 18-19.
- [10] Southern California Edison 2006 New Gen RFO, Transmittal Letter, August 14, 2006, pp. 15-16.

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

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

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

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

Overall Frameworks Used in Selected States Procuring FRS Supply¹³⁰

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

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

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Additional information About Products Recently Procured in Selected States Procuring FRS Supply¹³¹

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

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

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

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

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