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The Northeast Utilities System

September 29, 2006

Debra A. Howland
Executive Director and Secretary
New Hampshire Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, New Hampshire 03301-2429

Re: Investigation of Implementation of the Energy Policy Act of 2005
Docket No. DE 06-061

Dear Secretary Howland:

Enclosed please find an original and six copies of Public Service Company of New Hampshire's comments concerning the Standards Sections 1252 and 1254 of PURPA which the Commission is considering adopting in this proceeding pursuant to the Energy Policy Act of 2005.

Copies of this letter and the enclosed written comments have been provided electronically to the persons on the attached service list.

Very truly yours,

Gerald M. Eaton

Gerald M. Eaton
Senior Counsel

Enclosures

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DE 06-061
Time-Based Metering and Communications ("Smart Metering") Section 1252 of Energy Policy Act of 2005

Public Service Company of New Hampshire ("PSNH" or "Company") submits these comments relative to Section 1252 of the Energy Policy Act of 2005 ("EPACT"). PSNH submits its preliminary comments for the purpose of providing information pertaining to the Issues section contained in the consensus scoping document filed with the Commission on July 25, 2006 and to highlight key issues underlying implementation of so-called "Smart Metering" and associated time-based rate schedules.

The EPACT amended PURPA, inter alia, by adding five new standards to the list of ten federal standards previously included in PURPA. The five new standards relate to net metering, fuel sources, fossil fuel generation efficiency, time-based metering and communications, and interconnection. As with the pre-existing PURPA standards, the Commission may implement the federal PURPA standard or decline to implement such standard, as it deems appropriate. (PURPA Section 111(c)).

The new Standard 14 (time-based metering and communications) (PURPA Section 111(d)(14)) provides that electric utilities shall offer each customer class, and provide individual customers upon request, a time-based rate schedule that shall vary during different time periods and reflect the variance, if any, in the utility's cost of generating and purchasing at wholesale. As noted in the scoping document, the statute notes that the types of time-based rate schedules that may be offered include, but are not limited to:

> **Time-of-Use Pricing (TOU)**: price is broken into two or three time periods based on typical demand levels (peak, shoulder, off-peak) and is fixed for a predetermined period.
>
> **Critical Peak Pricing (CPP)**: the price is similar to TOU in most hours except it allows the utility to increase prices to a substantially higher level during extreme peak hours.
>
> **Real-Time Pricing (RTP)**: Prices are provided in real-time or near real-time with price notification from one hour to one day prior to use. This requires customers to monitor both price and usage in much more detail.

Standard 14 further states that each electric utility shall provide each customer requesting a time-based rate with a time-based meter capable of enabling the utility and customer to offer and receive such rate, respectively (also applies to customers whose energy is provided by a third party marketer).

Standard 14 does not indicate that state regulatory authorities must implement one form of time-based pricing over another nor does the Standard presume that any one form of pricing is the preferred method for utilities to implement for their respective customer classes. Indeed, as with other provisions in EPACT, a state regulatory agency is free to decline to implement any or all of the federal PURPA standards.

PSNH is providing the following comments and observations based on the requirements outlined in Standard 14 with consideration of the potential impact that significant rate structure changes have on customers and the impact that time-differentiated pricing may have on high-use commercial and industrial customers.

Preliminary Response to Listed Issues:

1. Has the state or the Commission already taken any action that may constitute "prior state action" under the Standard?

Yes. The Legislature, the Commission and the electric utilities all have taken action with respect to time-based metering and time-differentiated retail electric rates. New Hampshire has enacted statutes which require electric utilities to file optional time-of-use rates and time-of-day rates. RSA §§ 378-7-a. 7-b, and 7-c. These statutes were first enacted in 1978. PSNH has complied with these statutes by filing Delivery Rates R-OTOD and G-OTOD for its residential and small commercial customers. For its large commercial and industrial customers, PSNH's tariff provides that the customer may be billed for the Maximum Demand at the greater of their actual demand recorded during on-peak hours or 50 percent of the highest demand recorded in the off peak hours. Please see PSNH's discussion of time-differentiated delivery rates in response to Issue No. 7 below.

The Commission also investigated time-based advanced metering in the Advanced Metering Docket DE 03-013. As a result of the Commission's investigation, the parties and Staff entered into a Settlement Agreement which was approved by the Commission in Order No. 24,263 (January 9, 2004). In that Settlement, the state's rate-regulated electric distribution utilities agreed to install "Advanced Meters" for their large commercial and industrial customers. (NHEC proffered a proposal comparable to that of the Settlement.) Such meters were required to meet the following standards:

a. Be interval data meters with mass memory capability; i.e., the meter retains data for at least one complete billing month;

b. Include a modem capable of providing data to the customer, the customer's competitive energy supplier, and the distribution company; and

c. Be capable of recording and transmitting pulses.

For purposes of this definition, "pulse" means a contact closure produced by a watt-hour meter or other measuring device that represents a finite quantity measured by the meter. This quantity is typically energy (watt-hours), but could be reactive energy (var-hours or q-hours), or other quantities such as volts-squared-hours. Metering pulses can be used for recording metering quantities over an interval of time or for other uses such as telemetering, load management or local indication. Order No. 24,263 Settlement Agreement at 2, slip op. at 24 (January 9, 2004).

As a result of that proceeding, advanced meters have been installed for the utilities' largest customers, and optional tariff services "including remote access metering, pulse output service and interval data service (as defined in each Party's respective tariffs)" have been implemented. *Ibid.* The utilities also offer their largest customers the opportunity to participate in optional load control programs.

2. Qualitatively, what are the costs and benefits of time-based pricing for default service?

The costs, potential benefits and operational impacts that time-based pricing may have on individual customers or customers classes will vary significantly. Clearly, New Hampshire's large commercial and industrial customers operate in an increasingly price-competitive market where they must compete against businesses and manufacturers in other states or countries. The cost of electric energy can be a significant component of the cost of production for some large users, and providing these users with relatively stable energy pricing allows them to make determinations as to when or whether to use energy. PSNH commercial and industrial customers have generally expressed their preference that energy prices be reasonably known and predictable in order to assist them in establishing budgets, business plans and production schedules. Generally speaking, customers are likely to oppose a rate structure change which significantly increases their costs or produces greater price uncertainty. For those customers that do want time-differentiated energy pricing, the competitive market does provide this service as noted elsewhere in this document.

The potential electric system and energy cost benefits resulting from use of TOU, CPP or RTP rate structures are directly related to the ability and willingness of customers to proactively respond to retail price signals. Large customers that currently have more advanced metering, have facilities staffed by plant managers and, in some cases, have sophisticated energy management systems in place have a greater ability to respond to price signals and load conditions than the typical small residential customer. Such issues must be factored into class-specific determinations on whether a specific rate structure will have any material system benefit. Although Standard 14 does focus on energy pricing, it must be noted that PSNH's delivery charges are time-differentiated and have been for many years. Further detail on time-differentiated delivery rates is provided in PSNH's response to Issue No.7.

Depending upon customer adoption and reaction to TOU, CPP and RTP for energy rate structures, proponents of these rates note that certain benefits might occur, including:

- Overall demand reduction,
- Reduced peak loads, and
- Lower overall cost for energy (utility)

Whether any of these benefits occur, and how soon they materialize, are directly related to customer response to any such rate offerings.

3. Which costs are the responsibility of customers and which are the responsibility of competitive suppliers?

Allocation of costs resulting from time-differentiated energy pricing, whether due to implementation, administration or energy procurement for electric supply, shall depend upon the parties involved in the energy transaction. Energy supplied to a retail customer in New Hampshire by an unregulated competitive supplier reflects pricing determined solely by those two parties. The parties are free to determine how any transaction or supply costs are apportioned. PSNH's relationship with competitive energy suppliers and the specific costs for providing a wide range of services to such suppliers is clearly defined in Electricity Delivery Service Tariff – NHPUC No. 4, Terms and Conditions for Energy Service Providers. Aside from the supplier charges defined in this section of the Tariff, unless a charge is directly assessed to a customer or other entity, the expense generally becomes part of PSNH's overall cost of operations and is subject to recovery from all customers through retail rates.

4. What is the experience with "real time" pricing as a means to encourage demand response and promote retail access? What are the implications of this experience for implementing "real time" pricing in New Hampshire?

PSNH has offered its Voluntary Interruptible Program Rate VIP for many years. Rate VIP incorporates many of the characteristics of near Real Time energy pricing with voluntary curtailment of electric load by participating commercial and industrial customers. Rate VIP is typically operated during the high energy cost months of June through September each year. For the first time, it was also operated during the winter months of January through March, 2006 in response to natural gas supply restrictions. The objective of this interruptible load program is to establish a mechanism whereby PSNH can notify large commercial and industrial customers during times of high real-time New Hampshire zonal prices (NH zonal price) as determined by ISO-New England and request that they curtail load. It is open to larger customers (PSNH Rates GV and LG) who have hourly metering available to estimate the amount of load curtailment when interruptions occur. This estimate is based on hourly meter readings adjusted to account for normal load shapes and temperature differences. Participation and interruption is completely voluntary, with customer bill credits based upon actual interruption performance combined with the NH zonal price during each curtailment hour. Interruption of load in this program is generally called when the NH zonal price for the next hour is projected or anticipated to exceed $200 per MWh ($0.20/kWh) and will terminate when the next hour's NH zonal price is expected to be less than $200 per MWh. Customers must be willing to interrupt 100 kW or 10 percent of their load, whichever is greater. During the last several years, PSNH has been able to achieve approximately 20 megawatts of voluntary participation among its large customers. Although the program is focused on energy prices in order to produce savings, the hours when real-time energy prices are highest frequently occur when load in New England is also high. During the July 18, 2006 VIP interruption, PSNH obtained an estimated participation rate ranging from 33% to 48% during the hourly intervals when VIP curtailments were in effect. It should be noted that the bill credit for participants under Rate VIP must be calculated manually by PSNH's Large Power Billing (LPB) Department since the billing system used to bill Rate GV and LG customers can not perform the calculation. PSNH has been able to employ a manual calculation since the credit does not need to be applied during the same billing month that the interruption occurs, and there are generally only a few days during the summer that Rate VIP curtailments are implemented.

If Rate VIP provides any insight into time-differentiated pricing, customer feedback over the years seems to indicate that an effective price response program should be conducted on a voluntary basis, limited in frequency so that curtailments produce the maximum benefit and designed so that interruptions do not unreasonably affect the operations of participating customers.

As noted above, real-time pricing is already available on the competitive market. At least one supplier is offering a form of real-time pricing for energy service whereby customers may purchase directly from ISO-NE. PSNH supports this offering and has modified the language in its tariff to make it clear that customers can take self-supply service.

5. Can the demand response benefits of "real-time" pricing be achieved without the installation of energy management control systems?

As stated in Issue No. 4, PSNH's practical experience with a form of RTP is Rate VIP and the response to this question is based on that program. PSNH has not had a need to collect data from participating customers indicating the prevalence of specific energy management control systems, the methods used by such systems to monitor and control plant functions, or the actual role of these systems during curtailment periods.

In operating the Rate VIP program, it has become clear to PSNH that plant management is actively involved in managing the load reductions, regardless of the existence of such energy management systems. One of the first steps taken during curtailments under Rate VIP is the notification of key customer contacts listed on the Rate VIP enrollment forms. These individuals are directly notified by PSNH of the interruption start time, and it is assumed that these same individuals are fully involved in implementing the customer's load curtailment. Given the limited number of VIP curtailments, direct management control of the interruption appears to work well.

As stated earlier, many large customers have on-site facility managers. These customers, using PSNH's advanced metering, have direct access to meter pulses which they can then use for their own load management systems. To the extent that the customer's load is controllable, this combination of advanced metering and customer load management may enable them to respond to time-differentiated pricing in a way that maximizes the benefits. This type of customer might be expected to contract with a competitive supplier to take advantage of time-differentiated or real-time pricing.

6. What are the operational benefits (e.g., fewer estimated readings, meter reading labor cost savings, load data for engineering analysis, more efficient outage management, remote connect and disconnect functionality, and improved customer service) and challenges associated with smart meters?

In responding to this question which refers to so-called "smart meters", PSNH's assumption is that any transition to such "smart metering" might be evaluated when considering the implementation of some form of automated meter reading (also known as "AMR") technology. A program to invest in "smart metering" can be, and likely would be, separate from any decision to invest in AMR. However, the benefits listed in Issue No. 6 appear to indicate that the investment in smart metering was made in conjunction with AMR technology.

In summary, the potential operational benefits for a fully functional, system-wide, AMR deployment could include:

1. Significant reduction in labor costs associated with meter reading.
2. More accurate and timely identification of outages and subsequent restoration efforts.
3. Improved customer service using up-to-date metering data for on/off readings (off cycle reads) and resolving billing questions.
4. If the AMR system provides load profile data, Engineering would have access to accurate system loading information that may be aggregated and analyzed in whatever fashion they require.
5. Some AMR systems offer tampering detection features (although some users report that these have proven to be problematic due to false alarms).
6. Elimination of "unsafe" or "hard to read" meter reading issues.
7. Ability to disconnect/reconnect customers remotely.

These potential benefits would be partially or completely offset by the cost of purchasing, testing, installing and maintaining the new equipment and associated software systems, the loss of personnel for other uses such as storm restoration, collections, or lineworker feeder systems and the cost of premature retirement of functioning metering equipment.

Note that not all AMR systems provide the full set of potential benefits listed above. Some systems offer only a subset of those benefits. Some systems that promise a full set of benefits/features are not practical for implementation across PSNH's service territory due to its rural nature (e.g., full radio frequency (RF) coverage would be cost-prohibitive in rural areas). Some potential benefits would require a substantial investment in IT systems capable of managing an extremely large amount of load profile data before yielding the desired information. Regardless of the specific AMR deployment selected, all of the systems have substantial capital and start-up costs and are likely to have numerous implementation issues that would need to be resolved before the system functioned as designed.

7. Which time-based rate structure is appropriate for each customer class in each utility?

PSNH currently offers time-differentiated prices for each of its major rate classes. For its largest customers (Rate LG), the energy charge contains a blocked on-peak charge and an off-peak charge, and the demand charge has a "night-time forgiveness" provision under which off-peak demand is reduced by 50% in the determination of maximum demand. Its next largest class (Rate GV) also has the night-time demand forgiveness provision in the determination of billing demand, and the energy charge includes a long hours' use discount. While a long hours' use discount is not technically a time-differentiated energy charge, it provides for lower energy charges for customers with higher load factors (and therefore with more energy usage during off-peak periods). PSNH's small general service class (Rate G) includes an optional time-of-day rate for customers with thermal storage devices and other applications approved by PSNH. This rate has a time-differentiated distribution charge for energy, and the distribution demand charge is only applied to on-peak demand. Finally, PSNH offers an optional time-of-day rate for residential customers with time-differentiated energy charges for both distribution and transmission.

Time-differentiated rates should be offered only on an optional basis for smaller customers because those customers are the least likely to be able to significantly alter their consumption habits or absorb the higher cost of implementation. Larger customers are more sophisticated in their use of energy and are more likely to be able to absorb the higher costs of implementation of time-differentiated pricing. Moreover, the metering that is utilized for the largest customer class includes the ability to measure the customer's load on an interval basis, thus eliminating any incremental metering cost for time-differentiated pricing. Therefore, for the largest class of customer, it's appropriate to offer some form of time-differentiated pricing within a utility's standard pricing; as PSNH does within its current tariff. Moreover, these larger customers also have more readily available time-differentiated pricing options from the retail energy marketplace.

8. **Does the standard raise factual issues that should be considered on a utility-by-utility basis? For example, does 369-B:3, IV(b)(1)(A) prohibit "real time" pricing for any PSNH customer class? In addition, does the statutory requirement that UES and National Grid procure their power requirements in the market prohibit time-based pricing for any customer class?**

When viewed from an average cost or total cost basis, there are factual distinctions among New Hampshire regulated utilities. However, from a marginal cost basis, all New Hampshire utilities are affected in a similar manner since all New Hampshire utilities participate in a New England-wide wholesale energy market managed by ISO-NE under Federal Energy Regulatory Commission jurisdiction. PSNH's portfolio of resources used to serve its Default Energy Service customers is different from other electric distribution utilities in New Hampshire since a portion of PSNH's portfolio includes owned generation. However, PSNH purchases its marginal, or incremental, Default Service (Energy Service) requirements from the same marketplace as other New Hampshire utilities. PSNH's Energy Service rate is currently set on a semi-annual basis using estimated data and reconciled by comparing actual costs with actual revenues. RSA 369-B:3, IV(b)(1)(A) provides:

> From competition day until the completion of the sale of PSNH's ownership interests in fossil and hydro generation assets located in New Hampshire, PSNH shall supply all, except as modified pursuant to RSA 374-F:3, V(f), transition service and default service offered in its retail electric service territory from its generation assets and, if necessary, through supplemental power purchases in a manner approved by the commission. The price of such default service shall be PSNH's actual, prudent, and reasonable costs of providing such power, as approved by the commission;

The cost of PSNH's generation does not necessarily vary with time (i.e. the "fixed" cost of generation). PSNH bids its generating plants into the day ahead ISO-NE market based on its variable costs (e.g. fuel) and receives payments based on the ISO-NE "clearing price" for energy. Generation from PSNH's plants is generally not sufficient to supply the entire load of customers taking energy service from PSNH. PSNH purchases supplemental power to meet the portion of Energy Service load not supplied from its generating plants through bilateral contracts or by taking service hourly as needed from the ISO-NE spot market. There is no specific hourly price for PSNH-supplied energy other than that set within the ISO-NE market in the same manner as that set for any load served through a New Hampshire electrical "node".

9. Should implementation of time-based pricing be mandatory, voluntary, or some combination of the two?

Mandatory implementation of TOU, CPP or RTP in New Hampshire is not required pursuant to PURPA. Implementation of a mandatory energy (Default) service time-based pricing structure that a customer finds punitive can simply be avoided by a customer through market purchases of a design more to their liking. Therefore, PSNH recommends that any new time-based pricing plan be implemented on a voluntary basis.

Any retail customer that wants to avail themselves of hourly energy pricing based on the day-ahead or real-time market can do so through a competitive electric supplier through what has become known as the "direct purchase" option previously approved by the Commission. Some customers already have done so on a voluntary basis. The customer would be under a separate agreement with the supplier and would be billed directly by the supplier for energy for each billing month

10. What are the available technology options for measuring energy and demand on an interval basis? What are the strengths and weaknesses of each? Which technologies make the most sense for each utility and each customer class?

All major meter manufacturers offer load profile (LP) recording in their product offerings. Some advanced metering infrastructure (AMI) systems are designed to provide LP data as well, usually providing a small amount of "on-board" memory in the meter with frequent communications to a "collector" that is equipped with a larger amount of memory and is configured to up-load that data frequently (typically daily) to avoid losing any intervals of LP data.

Conventional LP recording meters offer the advantage of on-board storage of a large amount of data (usually more than 2 months of 30 minute interval data). This prevents gaps in data if the meter cannot be read on the regular schedule. These meters are usually capable of being equipped with a telephone modem, enabling remote access to the LP data. There is a great deal of programming flexibility regarding the quantities to be recorded, the interval length, and the amount of data to store in active memory. Some disadvantages to this approach include "throughput" limitations for telephone read meters (may take 1~2 minutes per meter for daily reading, 3~5 minutes per meter for monthly read meters), phone line communication problems (especially for cell phone connected meters), and the cost of the phone line.

If no modem is installed, the data must be gathered by "probing" the meter using a hand-held reading system. Some disadvantages to this approach include the need to visit each meter and the time it takes to download the data (faster than a phone reading but slower than simple kWh visual reading).

All of PSNH's large customers (Rate LG and Rate GV) are already equipped with a recording meter, including approximately 120 Rate LG and 1336 Rate GV customers. Based on data from 2005, these customers represent approximately 44% of the total annual kWh usage and 40% of the system kW demand during peak demand periods.

PSNH's approach of using LP recording meters on large customer accounts, programmed for 30 minute LP intervals, has worked well. It allows detailed analysis of kWh usage and demand data, enables high use customers to access their data via the Energy Profiler – Online (EPO) System, and enables flexible TOU rate analysis for any of these customers, if required. PSNH rarely has data "gaps," and when they occur it is typically due to equipment failures or required testing – not because of a temporary communication issue. PSNH's current approach is a proven, reliable, and flexible way to gather LP data. The mature technology for recording, retrieving, analyzing and storing LP data works well and requires no further infrastructure investments compared to a new AMI system. By contrast, if an AMI system was implemented where all meters provide interval data there would be a huge increase in the amount of data to manage, requiring a significant investment in data management software and hardware along with personnel to support the system. This expense is often excluded from the price of the AMI system being sold by AMI vendors, although some vendors are beginning to offer more complete system solutions.

When PSNH evaluated the AMR/AMI systems available in 2004, no system could offer LP capable metering for PSNH's entire service territory in a cost effective and reliable manner. AMI systems of this type are typically based on a fixed network RF technology that would be impractical for many parts of New Hampshire. That type of technology is best suited for densely populated urban areas. In PSNH's evaluation, rural areas were best covered by Power Line Carrier (PLC) systems. The PLC systems are typically not used or designed for gathering LP interval data due to the slow communication speeds required for signal propagation through the power line equipment (distribution transformers, etc.).

11. What are the available technology options for communicating with interval meters and transmitting the price or cost information to utility and customer? What are the strengths and weaknesses of each? Which technologies make the most sense for each utility and each customer class?

The AMR/AMI systems with which PSNH is familiar, and that are currently in use, are primarily designed to transmit energy and demand data, not pricing information. PSNH does not believe it is prudent to use metering equipment as a conduit for time sensitive pricing information for its retail customers. It is too likely that a communication problem would delay/prevent the transmission/receipt of this type of information, leading to a significant number of customer complaints and associated billing issues. It is generally much more reliable to use the meter to measure, store, and transmit energy and demand information, then perform any required conversion to dollars and cents outside of the metering system based on the energy, demand, and/or interval data captured by the meter. There are other ways to alert customers to the price of electricity, such as links to a web site, paging systems or automated voice message systems.

12. What is the current availability of interval meters and communications equipment and systems by customer class? What is the timeline for acquiring such capability if not currently available?

Currently, PSNH has LP recording meters installed on essentially all Rate LG and Rate GV accounts– (approximately 1500 meters). Approximately 200 of these meters are connected to a phone line. Most phone read meters are connected to "land lines". Approximately 12 meters are connected to cell phones. As cell phone technology has developed, many existing modem equipped meters have become incompatible with the newer cell phone technology. In addition, the required type cell phone coverage is unavailable or unreliable in many parts of New Hampshire. One alternative PSNH is exploring is satellite modem technology. It promises to overcome most/all of the coverage issues, but PSNH has not yet completed testing of this type of technology and such technology may be excessively expensive.

13. Does each utility currently have the capability to bill customers based on "real-time" pricing? If not, what is the timeline for acquiring such capability and what changes need to be made?

PSNH's Customer Information System (CIS, for billing residential and small-commercial customers) and the Large Power Billing System (LPB, for large commercial and industrial customers) as currently designed and coded cannot bill on a real-time basis. Additionally, there are several significant technical and business process issues involving meters (e.g. smart meter types), meter data management (e.g. MV90) and supporting communications infrastructure that must be implemented in order to provide a complete end-to-end real-time billing and pricing solution. It should be pointed out that most of the sales and purchases in New England are transacted through the "day ahead" market rather than "real-time". Even in a "real-time" daily market, billing is not performed for days or months after the fact once the final settlement prices are known and billing data is collected and processed.

Without a complete set of detailed requirements and specifications, it is nearly impossible to accurately estimate the time and cost to support a change in PSNH's automated billing systems to process hourly price and load information. However, using past large scale Customer Service projects as an estimating guideline, it is highly likely that the application system changes, not including meters and associated infrastructure, would require approximately 2 to 3 years of work and cost in the range of $2 million to $4 million. It is important to note that PSNH's CIS application is under a "degrees of freeze" change control moratorium and is scheduled to be replaced with a new CIS system (referred to as "C2") in the fourth quarter of 2007 as described below.

The C2 system, while more modern and flexible than PSNH's existing CIS system, is not capable of processing hourly price and load information without significant modification. Regardless of the system used, PSNH does not anticipate sufficient customer interest or volume to justify the levels of expenses that would be required to develop an automated real time pricing and customer information system. If such pricing were implemented for a few customers (or even one), significant manual billing and account maintenance processes would need to be established.

14. What are the monetary costs and benefits of time-based pricing?

As stated in prior sections of this document, PSNH has identified the billing and metering systems as two critical areas that would require extensive amounts of time, expense and capital to modify in order to make them function properly for certain time-differentiated energy pricing options (such as RTP). Potential monetary benefits might include any savings of energy or capacity costs due to customers shifting load, or eliminating load, from high cost energy periods. Without knowing how customers would shift or eliminate load, and at what times, PSNH cannot accurately quantify the monetary benefit.

15. What implementation issues should be considered? For example, should utilities develop education and outreach plans, develop targeted technical assistance programs, and/or implement pilot programs? What would these efforts entail?

The amount, duration and depth of any education or outreach programs is likely to be proportional to the amount of rate impact and inherent complexity of the time-differentiated pricing selected, if any. Whether such rate offerings are voluntary or mandatory will also determine the number of customers that need to be reached by this effort. As indicated elsewhere in this document, PSNH recommends that any time-differentiated rate offerings be established on a voluntary basis for PSNH's retail customers. Customers that want to avail themselves of a RTP energy option can do so by moving to the self-supply or competitive supply markets.

16. How should existing default service wholesale supply contracts be treated if time-based or "real-time" default service is implemented and starts before the end of the existing contract(s)?

PSNH currently provides default energy service from owned-generation, supplemented with wholesale power purchases. The supplemental power purchases are typically for a period of days or weeks but may be contracted for months before the actual purchase is made. Consequently, PSNH can adjust to a new set of conditions that would alter its wholesale purchases in a period of days or up to a year

17. What "real-time" pricing information is available and how will it be communicated to customers? What adjustments do utilities expect to make to these "real time" prices?

The definition of Real-Time Pricing (RTP) includes the provision that customers must be notified of price "from one hour to one day prior to use". The obvious logic underlying this premise is that retail customers should be allowed sufficient time to react to price signals. Many large customers, including those with energy management systems installed at their facilities, still rely on plant management to make final determinations regarding load curtailment which require some time to implement. When implementing curtailments under the Rate VIP program, PSNH has always focused on providing customers with as much advance notice as possible in order to maximize the potential benefit and customer response under the program. The reference to "from one hour to one day prior to use" appears to preclude the use of ISO-NE's Real-Time Locational Marginal Price (RT LMP), which is not available until the hour of energy consumption has concluded. One potential alternative for RTP is the ISO-NE's Day-Ahead Locational Marginal Price (DA LMP). These hourly prices are posted on the ISO-NE's public website at approximately 4:00PM on the day prior to consumption. While there can be significant hourly differences between the DA LMP and the RT LMP, over a longer time period (e.g. a month or a year) these differences are minimized.

18. How will "real-time" prices be reconciled with actual supply prices? How should these cost differences be collected from customers? Can the utilities provide billing information on an hourly basis which reflects both real-time price and eventual settlement price?

It appears highly likely that utility implementation of RTP could create significant over- or under-collection of energy costs. The applicable "real-time" hourly price (e.g. the ISO-NE Day-Ahead LMP) will never exactly equal a utility's actual cost of supply obtained in part or in whole from bi-lateral contracts unless, of course, the bi-lateral contract prices are set to track the hourly prices established by the ISO-NE (which has not been the practice of utilities within New England). The resulting cost differences could be rolled into the default service rate in a subsequent period (e.g. monthly, quarterly, or annually). It would also need to be decided whether or not this collection should be a bypassable or non-bypassable charge.

Since utilities do not know the real time price until after the price is set, utilities cannot provide such information to customers until after the period has expired. Even then, such prices are subject to later adjustments and reconciliation by ISO-NE. Such information is available directly from the ISO-NE to customers in the same manner it is available to PSNH.

19. How will this information be used? What control equipment is available on the customer end? If pricing information is provided, what technology exists to take this information and use it to control load based on pricing inputs?

Companies have tried, sometimes unsuccessfully, for many years to promote widespread use of <u>residential</u> load control equipment. The benefits have not been great enough to justify the installation, programming, inconvenience, and operation/maintenance costs of this type of equipment. There is a tremendous amount of information available regarding advanced or next generation "smart" metering and the functionality likely to be available through such meters. As a general matter, PSNH believes that regardless of the technology employed the initial focus should be on large customers since any potential savings to other customers is likely to be far too small to justify the expense of implementation or the inconvenience experienced by customers. Because of their more concentrated load, large customers may be able to generate sufficient benefits to justify to added cost and inconvenience. The interval data for this type of customer is already available using existing, mature metering technology that is relatively inexpensive and very reliable.

ELECTRICAL INTERCONNECTION
GENERAL GUIDELINES FOR
LIMITED ELECTRICAL ENERGY PRODUCERS

These general guidelines are issued to present information and guidance to those who are considering a limited electrical energy production facility interconnection. A more detailed description of the Engineering requirements will be provided when all data is received on the proposed generating facility.

I. Safety Requirements

a. The connection of the facility to the PSNH system must not compromise the safety of PSNH's customers, personnel, or the owner's personnel.

b. An emergency shutdown pushbutton with facility status indicator lights, and a visible disconnecting device shall be made available for unrestricted use by PSNH personnel. The operation of the pushbutton shall cause all of the facility's generation to be removed from service, and shall block all automatic startup of generation. The status lights shall be located local to the pushbutton. A red light shall indicate that the facility has generation connected to the PSNH system. A green light shall indicate that all generation is disconnected from the PSNH system. The visible disconnecting device shall be located between the PSNH system and the facility's generation.

c. The generating facility shall not have the capability of energizing a de-energized PSNH circuit.

d. The generating unit must have the following minimum protective devices to separate the facility from the PSNH circuit:

1) Time overfrequency

2) Time underfrequency

3) Time overvoltage

4) Time undervoltage

These devices must be of utility grade as approved by PSNH. Certain interconnections may require additional devices. Recommendations concerning these devices will be made by PSNH.

e. Protective and associated devices may be required at the primary voltage level to detect ground faults that occur on the PSNH distribution circuit. These devices will operate to separate the facility and any ground current contribution from the circuit.

f. The short circuit interrupting device(s) must have sufficient interrupting capacity for all faults that might exist. This rating will be supplied by PSNH.

g. All shunt-tripped short circuit interrupting devices must be equipped with reliable power sources. A D.C. battery with associated charging facilities is considered a reliable source.

h. The generating facility is responsible for ensuring that the protective system and the associated devices are maintained in reliable operating condition. This maintenance should conform to utility standards.

i. Protection of the generating facility equipment for problems that might occur internal or external to the facility, is the responsibility of the owner.

II. Service Quality Requirements

a. The connection of the facility to the PSNH system must not reduce the quality of service currently existing on the PSNH system. Voltage fluctuations and excessive voltage and current harmonic content are among the service quality considerations.

b. Automatic reclosing of the PSNH circuit after a tripping operation(s) will occur, and its operation should not be affected by the interconnection.

III. Interface Requirements

a. All pertinent data on the equipment to be used at the generating facility shall be supplied to PSNH to assist in the interconnection study.

b. The interconnecting primary voltage level will be determined by PSNH. This determination will be based on the relative size of the generating facility compared with the existing PSNH distribution or transmission system in the area. Extension of existing circuits to a higher voltage level may be required.

c. The transformer winding connection to be used at the primary voltage interconnecting point will be specified by PSNH. For larger units, the requirement for a wye grounded primary connection may necessitate the use of a three phase interrupting device (breaker) at the primary voltage level. Depending on the system parameters, a current limiting reactor may be required in the neutral of the wye winding.

d. All synchronizing will be done by and at the generating facility.

e. Power factor correction may be required on certain interconnections.

f. Any PSNH system modifications required to accept the generating facilities will normally be performed at the facility owner's expense. The necessity for any such modifications will be formally conveyed to the facility owner by PSNH when all of the proposed generating facility data is received.

Aubrey L. Spaulding
January 14, 1981
Rev. 1, Jan. 21, 1981
Rev. 2, Feb. 10, 1982

Minimum Metering and Telemetering Required
For Interconnection to the PSNH Energy Delivery System
January 14th, 2005

This document is intended to describe equipment, technology and coordination necessary to meet the minimum metering and telemetering requirements of Independent Power Producers or Merchant Generators (IPP) desiring interconnected operation with the Public Service of New Hampshire (PSNH) transmission and distribution system. Satisfactory completion of these requirements is necessary prior to testing the generation units interconnected with the PSNH Energy Delivery system.

The PSNH Electric System Control Center (ESCC) is the SCADA center responsible for the safe and reliable operation of the PSNH 34.5 kV distribution system and the PSNH bulk transmission system operating at 115 kV and 345 kV.

The minimum requirements outlined below allow the ESCC to discharge these responsibilities. They apply to any generating units that may export 1 mW or more onto the PSNH grid. It does not include a generating unit that reduces or serves the customer's own load.

These minimum requirements are intended to satisfy the reliable operating criteria of the PSNH Energy Delivery system. They do not represent the metering and telemetering requirements to participate in the Independent System Operator - New England (ISO-NE) Markets. ISO-NE is the operating arm of the New England Power Pool (NEPOOL) [section II A]

I. Minimum ESCC Metering and Telemetering Requirements.

A. Generation Connected to PSNH at 34.5 kV or higher.

Generating units with a capacity of 1 mW or greater, directly connected to the PSNH transmission or 34.5 kV distribution systems will be required to provide the ESCC with the following data:

1. Instantaneous net mW adjusted to the delivery point.
2. Instantaneous mVAR adjusted to the delivery point.
3. High side voltage as measured on the generator side of the delivery point.
4. The breaker status of each individual generator, and in the case of combined units, the status of a single breaker, which has the ability to isolate the combined units.

B. Generating Units connected to the PSNH medium voltage Distribution System.

Generating units with a capacity of 1 mW or greater, directly connected to the PSNH **medium voltage** distribution system (operating at less than 34.5 kV) may be required to provide the ESCC with the following data:

1. Instantaneous net mW adjusted to the delivery point.
2. Instantaneous mVAR adjusted to the delivery point.

C. Revenue Meters.

Except for the ISO-NE requirements to provide Revenue Telemetering megawatt-hours (mWh) for generating units and tie lines as outlined in ISO-NE OP # 18, the ESCC will not collect revenue mWh. Instead, the ESCC will use a calculated mWh value (cmWh) based on the net mW data being telemetered to the ESCC. This cmWh may be used to provide back-up revenue data.

II. ESCC Role in regard to NEPOOL

The ESCC is one of the four NEPOOL Local Control Centers responsible for coordination and operation of the bulk generation and transmission assets; its area of responsibility roughly coincides with the State of New Hampshire. ESCC Local Control Center responsibilities include coordinating the operation and maintenance of the bulk transmission facilities and generating facilities with the adjacent Local Control Centers and ISO-NE. The ESCC is also responsible for monitoring and dispatching unit reactive in order to maintain the voltage profile of the distribution and bulk transmission system.

A. ISO-NE Metering and Telemetering Requirements.

This section includes information on ISO-NE Metering and Telemetering requirements that are outlined in several ISO-NE Operating Procedures and ISO-NE Market Rules. The requirements are based on the size of the generating units, as well as the ISO-NE Markets in which the unit is participating. It must be understood that these requirements are wholly separate from those required by PSNH. It is provided in the interest of guidance to those wishing to participate in the New England Energy Markets. The following is a listing of the ISO-NE documents that outline the metering and telemetering requirements for generating assets participating in the ISO-NE Markets.

NEPOOL Market Rules and Procedures.
NOP #2 Maintenance of Communications, Computers, Metering, and Computer Support Equipment.
NOP #14 Technical Requirements for Generation, Dispatchable and Interruptible Loads
NOP #17 Load Power Factor Correction.
NOP # 18 Metering and Telemetering Criteria.

It is the IPP responsibility to acquire the documents from ISO-NE and to comply with the ISO-NE metering and telemetering requirements. These documents are available under "Rules & Procedures" on the ISO-NE website, www.iso-ne.com/main.html.

B. Inter Control Center Communications Protocol Node (ICCP)

The ESCC is required to provide IPPs located within the New Hampshire Local Control Center access to the ISO-NE ICCP Node located at the ESCC. Connection to this ICCP Node will enable the transfer of the telemetered data to the ESCC, from there on to the ISO-NE host computers. IPPs which are required to provide telemetered data to ISO-NE will have to establish the required data communications links to the ESCC as outlined below. It will be the responsibility of the respective generating facility to install and maintain a Remote Terminal Unit (RTU) and telephone circuit to the ESCC in accordance with NOP #2.

III. Communications Links to the ESCC

A. Voice Communication

IPP operators must establish a dedicated voice telephone line between the ESCC System Operations Supervisors and the generating station control room operators. This is not an automatic ring down (ARD) requirement. The operation entity for the new IPP will need to provide the ESCC with station control room number and an alternate 24/7 number.

B. Data Communication

IPP operators who are required to provide telemetered data to the ESCC and to ISO-NE will have to establish and maintain the required data communication links to the ESCC.

IV. RTU Technical Requirement

AREVA is the vendor for the host computer at the ESCC. Any RTU that provides SCADA data to the ISO-NE and to the ESCC will meet the following specifications:

1. The selected SCADA RTU must communicate with the ESCC SCADA host computer using the Landis & Gyr Telgyr 8979 protocol. AREVA refers to this protocol as Landis & Gyr 12 bit RTU. The RTU and protocol must perform all function codes and data acquisition procedures required by the host computer located at the ESCC. PSNH is currently using the Wesdac D20ME RTU manufactured by GE/Harris. This RTU system is what is known to work with our current ESCC SCADA Host. The RTU comm. port used to communicate to the ESCC SCADA Host is set for 9600 baud. Any RTU and vendor version of the 8979 protocol must be backward compatible to the Landis &Gyr Telegyr 8979 Revision A (document 1008979000) used in the ESCC SCADA Host.

2. Install a stand-alone Digital Service Unit (DSU) manufactured by Telenetics, model number DDS/MR64, # TEL 6456524700020 at the IPP RTU site.

3. Provide the cable used from the RTU at the generating station to the DSU with the following serial cable from GE Harris, P/N 977-0128/60-00A.

4. Provide to the ESCC a rack mounted DSU manufactured by Telenetics, model number DDS/MR64 # TEL 6456524600010.

5. Install and maintain a 56K BPS DDS2 telephone line between the IPP RTU and the ESCC located at 44 West Pennacook Street, Manchester, NH.

6. Provide an uninterruptible power supply (UPS) to the IPP DSU and RTU with a burden of at least 8 hours.

Minimum Metering and Telemetering Required
For Interconnection to the PSNH Energy Delivery System
January 14th, 2005

Notes:

- Specific and updated protocol and RTU requirements will be provided on request.

- Any other vendor's equipment will have to meet all these requirements and may have additional time and material charges.
- It is strongly recommended that PSNH be contacted to ensure that compatibility issues are properly addressed, before any equipment described above is ordered.
- The first three analog points must be configured for A/D calibration points (Null, -90% & +90%)
- All analog points are 12 bits analog, unsigned.

V. Coordination of Schedules for Installation and Testing.

Any IPP desiring interconnection with the PSNH Energy Delivery System should be mindful that satisfactory completion of these requirements is necessary prior to testing the generation units interconnected with the PSNH delivery system.

An RTU Commission Date for completion of all requirements of this addendum will be selected by the IPP and provided to the ESCC.

No later than 45 days prior to RTU Commission Date, IPP must provide the technical staff at the ESCC with a tabular list of SCADA point names and addresses, in a format similar to the following table.

SAMPLE TAB SHEET: CONFIGURATION OF D20 RTU			
Card Address: ADC			
0	Calibration	Null	Reference - Zero
1	Calibration	-90%	Reference - Low
2	Calibration	+90%	Reference - High
Card Address - ANA			
0	Tie line MX	reactive	Full Scale =?? MX, (at the interconnection)
1	Tie Line mW	net power	Full Scale =?? mW, (at the interconnection)
3	Bus kV	Voltage	Full Scale =?? kV
Card Address: INDS (SOE)			
0	Breaker	Unit 1	Open/close
1	Breaker	Unit 2	Open/close
2	Breaker	Utility Main	Open/close
Card Address: INDO (Status Indication)			
0	Breaker	Unit 1	Open/close
1	Breaker	Unit 2	Open/close
2	Breaker	Utility Main	Open/close
3	Spare		
4	TT Guard	TT Guard Freq.	Alarm/normal

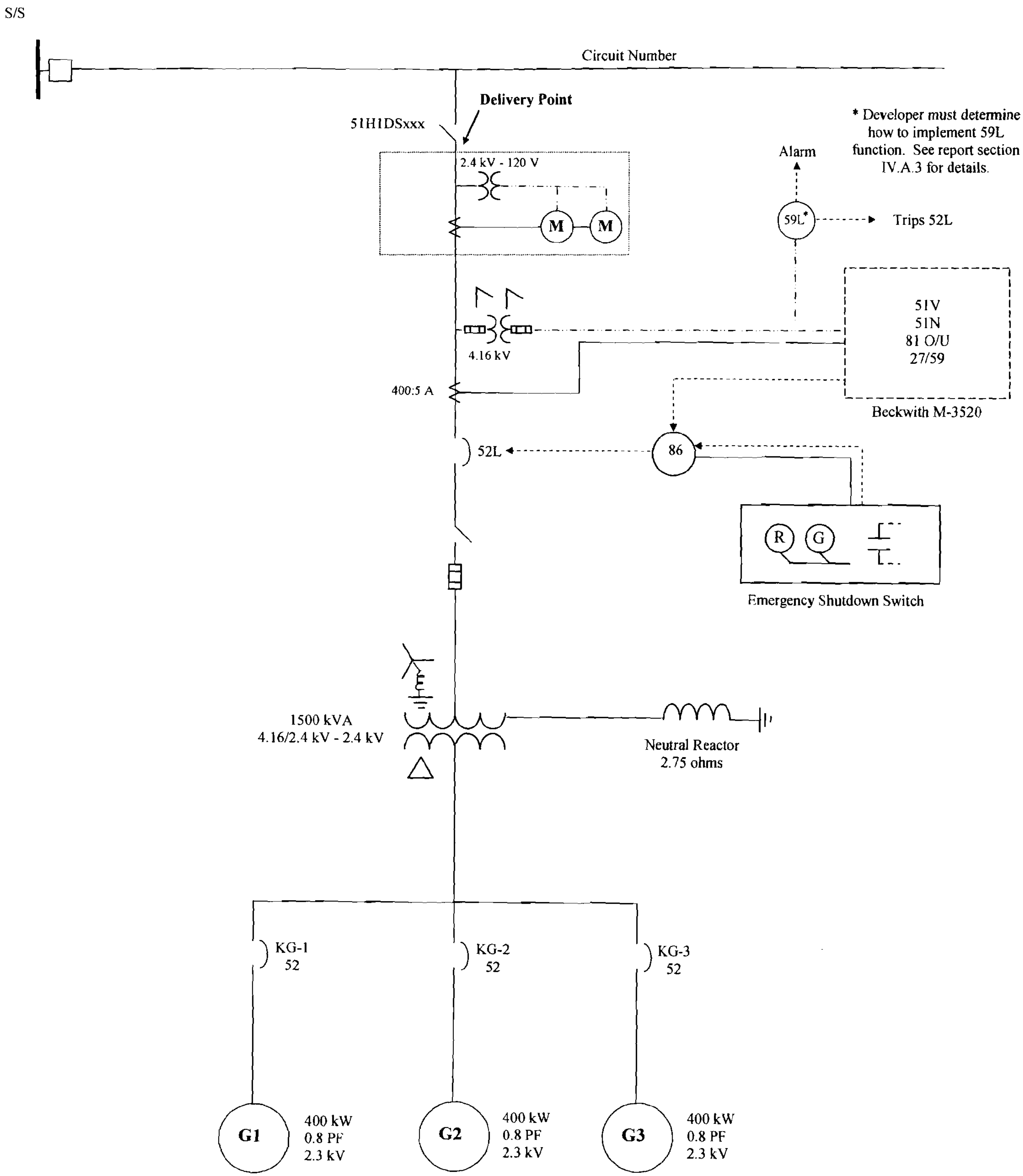
No later than 15 days prior to RTU Commission Date, the IPP will coordinate a test of the communications link and the RTU points tested on the Development System at the ESCC.

No later than 48 hours to RTU Commission Date, the IPP will coordinate a point by point test with the ESCC, to verify the RTU status, indication and analog scaling, with the ESCC Production SCADA system.

Coordination of schedules can be initialized by contacting the ESCC at (603)-634-3766.

VI. Document Control Information

Revision Number	Issue Date
Rev. 0	12/21/2001
Rev. 1	1/14/05



Partial One-Line Diagram
Generic SESD #xxx
SK-Init-xxx-1
Engineer Name, Date

PSNH INTERCONNECTION REPORT
FOR
CUSTOMER GENERATION

GENERIC 1+ MW HYDRO

<u>FINAL REPORT</u>

SESD SITE NO. 999

Engineer's Name
Date

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I. INTRODUCTION

A study has been performed to determine the impact of this facility on the PSNH system. All technical analysis was based on the equipment listed under Section II, and the facility arrangement illustrated on partial one-line diagram SK-XXX-999-1. Where actual site-specific data was not readily available, estimated or "typical" values were utilized in any required calculations. Any deviation from the listed equipment and/or the illustrated configuration may have significant safety and/or technical ramifications. Consequently, if changes are anticipated now or in the future, PSNH should be informed immediately so that the requirements and recommendations contained within the report may be revised where necessary. This procedure will ensure that the Developer is informed of PSNH requirements in a timely fashion and should eliminate the delays and expense which could otherwise be experienced by the Developer.

II. DESCRIPTION OF MAJOR COMPONENTS

A. Description Of Facilities

The Developer will operate three (3) hydro powered synchronous generators at their Town, State site, interconnected to PSNH in Location, NH. The generation capability of this development will be 1,200 KVA. The generators will be tied through the existing 2.4 kV site electrical distribution system to the 4.16 kV, 51H1 line out of Salmon Falls S/S.

B. Electrical Components

1. Generators (3) - Synchronous, 2.3 kV, 400 KW, 0.80 pf.
2. Exciters - (1) 50 KW Rotating, (2) Static
3. Generator Step Up Transformer - 1,500 kVA, 4.16/2.4 kV reactance grounded wye – 2.4 kV Delta (Z=5.9%).
4. Neutral Grounding Reactor - 2.75 Ohms at 60 Hz. Details per Section IV.A.4.

C. Mechanical Components

1. Turbines (3). Unknown manufacturer and model.

III. PSNH REQUIREMENTS - GENERAL

A. Safety Considerations

1. The connection of the facility to the PSNH system must not compromise the safety of PSNH's customers, personnel, or the owner's personnel.

2. The generating facility must not have the capability of energizing a de-energized PSNH circuit.

3. An emergency shutdown switch with facility status indicator lights, and a disconnecting device with a visible open shall be made available for unrestricted use by PSNH personnel. The operation of the switch shall cause all of the facility's generation to be removed from service, and shall block all automatic startup of generation until the switch is reset. The status lights, mounted with the shutdown switch, shall be located outdoors at a position acceptable to PSNH Operating Division personnel. A red light shall indicate that the facility may have generation connected to the PSNH system. A green light shall indicate that all generation is disconnected from the PSNH system. The lights shall be driven directly from auxiliary switches located on the facility's breaker(s). The disconnecting device with visible open shall be located between the PSNH system and the facility's generation.

4. The Developer is responsible for determining and applying the complete settings for all non PSNH required protective relays. PSNH will determine, at the Developer's expense, voltage, frequency and current set points for PSNH required protective functions (once more, the Developer is responsible for determining and applying the complete settings of these relays).

5. A PSNH approved testing company will be required to verify the proper functioning of those protective systems required by PSNH. This work will be performed at the Developer's expense.

6. The generating facility has full responsibility for ensuring that the protective system and the associated devices are maintained in reliable operating condition. PSNH reserves the right to inspect and test all protective equipment at the generator site whenever it is considered necessary. This inspection may include tripping of the breakers.

7. The short circuit interrupting device(s) must have sufficient interrupting capacity for all faults that might exist. The PSNH system impedance at the facility will be supplied on request.

8. All shunt-tripped short circuit interrupting devices applied to generators must be equipped with reliable power sources. A D.C. battery with associated charging facilities is considered a reliable source.

9. All synchronous generator facilities must be equipped with battery-tripped circuit breakers.

10. Any protection scheme utilizing AC control power must be designed in a fail-safe mode. That is, all protective components must utilize contacts which are closed during normal operating conditions, but which open during abnormal conditions or when control power is lost to de-energize the generator contactor coil. These schemes may be utilized only with non-latching contactors and may not be used with synchronous generators.

11. A complete set of AC and DC elementary diagrams showing the implementation of all systems required by PSNH must be supplied for PSNH review. These drawings should be supplied as soon as possible so that any non-conforming items may be corrected by the Developer without impacting the scheduled completion date of the facility.

12. All voltage transformers driving PSNH-required protection systems must be rated by the manufacturer as to accuracy class, and must be capable of driving their connected burdens with an error not exceeding 1.2 percent.

13. All current transformers driving PSNH-required protection systems must be rated by the manufacturer as to accuracy class and must be capable of driving their connected burdens with an error not exceeding 10 percent at maximum fault requirements.

14. All PSNH-required protective relays, and any other relays which PSNH might be requested to test, must be equipped with test facilities which allow secondary quantity injection and output contact isolation.

15. It is not the policy of PSNH to maintain a stock of protective relays for resale to facility Developers. Since many protective devices have delivery times of several months, Developers are strongly advised to order them as soon as possible after PSNH type-approval is received.

16. Protection of the generating facility equipment for problems and/or disturbances which might occur internal or external to the facility is the responsibility of the Developer.

17. No operation of the facility's generation is allowed until all requirements in Sections III and IV of this report have been met, and all systems required therein, are in place, calibrated, and, if applicable, proven functional. This requirement may be waived by PSNH for a given system if generation is required to demonstrate the proper functioning of that system.

B. <u>Service Quality Considerations</u>

1. The connection of the facility to the PSNH system must not reduce the quality of service currently existing on the PSNH system. Voltage fluctuations, flicker, and excessive voltage and current harmonic content are among the service quality considerations. Harmonic limitations should conform to the latest IEEE guidelines and/or ANSI standards.

2. In general, induction generators must be accelerated to "synchronous" speed prior to connection to the PSNH system to reduce the magnitude and duration of accelerating current and resulting voltage drop to PSNH customers to acceptable levels.

3. In general, synchronous generators may not use the "pull-in" method of synchronizing due to excessive voltage drops to PSNH customers.

4. Power factor correction capacitors may be required for some facilities either at the time of initial installation, or, at some later date. The installation will normally be done by the Developer at his expense.

5. PSNH may need to make modifications to control systems and tap changers in the electrical vicinity of facilities whose installed capacity is close in magnitude to connected circuit load. Should this be necessary, the modifications will be made at the Developer's expense.

6. There is no automatic reclosing of the PSNH circuit, after a tripping operation. If automatic reclosing is required, it will be added at the Developer's expense.

C. <u>Metering Considerations</u>

1. Except for protection/control and metering voltage sensing and generator and/or capacitor contactor supply voltage, no unmetered station service AC shall be taken from the station service transformers.

IV. PSNH REQUIREMENTS - SPECIFIC

A. <u>System Configuration and Protection</u>

1. The facility must be arranged and equipped as per partial one-line diagram SK-XXX-999-1.

2. The following protective functions must be supplied and connected to automatically trip at least the breakers as shown. These devices must be utility grade as approved by PSNH.

51N	- Neutral Overcurrent, Trip 52L
81 O/U	- Over/Underfrequency, Trip 52L
27/59	- Under/Overvoltage, Trip 52L
51V	- Voltage Controlled Overcurrent, Trip 52L
59L	- System Overvoltage, Alarm/Trip 52L

3. The 59L functionality is required to avoid extended overvoltage conditions to PSNH customers on the system. A high drop-out to pickup ratio should be utilized to avoid nuisance trips of the breaker.

4. The facility generator step-up (GSU) transformer must have a delta - reactance grounded wye configuration.

The following neutral reactor is required:

a) Reactance: 2.75 Ohms at 60 Hz
b) Short Circuit Current: 500 A for 10 seconds
c) Continuous Current: 15 A
d) Insulation Class: 5.0 kV
e) System Voltage: 4.16 kV

The reactor must comply with IEEE Standard 32-1972, reaffirmed 1991.

Metering

The following neutral reactor is required:

a) Reactance: 2.75 Ohms at 60 Hz
b) Short Circuit Current: 500 A for 10 seconds
c) Continuous Current: 15 A
d) Insulation Class: 5.0 kV
e) System Voltage: 4.16 kV

The reactor must comply with IEEE Standard 32-1972, reaffirmed 1991.

B. System Metering

No system metering work is required. The metering currently installed at the point of interconnection meets PSNH requirements.

C. Primary Interconnection

No primary interconnection work is required.

V. PSNH PRICE ESTIMATES

The following estimates for labor, materials, and overheads are supplied as an aid to the Developer for financial planning purposes. Should the Developer elect to have PSNH perform any of the work described in the estimates, he will ultimately be billed for the full actual cost of any work performed, including overheads.

Authorization for PSNH to perform any of the work or supply any of the equipment described below must be forwarded to the Supplemental Energy Sources Department along with a minimum payment covering 50% of the estimated labor and 50% of materials cost. PSNH will neither perform work nor order materials until this requirement has been met.

A. System Protection

1. All protective relays at the generator plant, including equipment at the outdoor switchgear, will be purchased by the Developer. PSNH must be notified as to exact relay model numbers proposed before ordering to assure that proper setting capability exists for interfacing with the PSNH system.

SUBTOTAL $ 0.00

2. Engineering - PSNH review of control circuits, material specifications and development of PSNH required relay settings at the site. In addition, assistance with specifications and settings for related primary distribution equipment.

SUBTOTAL $ 0.00

SECTION A TOTAL $ 0.00

B. Metering

1. None.

SECTION B TOTAL	$	0.00

C. Primary Interconnection

1. Materials - NONE

SUBTOTAL	$	0.00

2. Labor, Overhead, Misc. - NONE

SUBTOTAL	$	0.00
SECTION C TOTAL	$	0.00
GRAND TOTAL (A + B + C)	$	0.00

VI. INTERCONNECTION EQUIPMENT OWNERSHIP, OPERATION AND MAINTENANCE

A. Delivery Point

For the purpose of establishing ownership, operation and maintenance responsibilities, the location of facility energy delivery to PSNH (the "Delivery Point") must be defined. At this facility, the delivery point will be the point just beyond the existing PSNH air break switch (on the customer side of the switch) leading to the three phase, primary utility metering.

B. Description of Responsibilities

1. PSNH will own and maintain all equipment up to the delivery point. The Developer will own and maintain all equipment from the delivery point into and throughout the plant.

2. The Developer is normally responsible for operating all equipment on the facility side of the delivery point. The only exception to this rule would be if special circumstances required PSNH personnel to operate the emergency shutdown switch and/or disconnect switch.

VII. DRAWINGS

A. Sketch SK-XXX-999-1 is attached.

DE 06-061
Interconnection of Distributed Resources
Section 1254 of the Energy Policy Act of 2005
Public Service Company of New Hampshire's Initial Written Comments

Public Service Company of New Hampshire ("PSNH" or "Company") submits these comments relative to Section 1254 of the Energy Policy Act of 2005 ("EPACT"). PSNH submits its preliminary comments for the purpose of providing information pertaining to the Issues section contained in the consensus scoping document filed with the Commission on July 25, 2006.

The EPACT amended PURPA, inter alia, by adding five new standards to the list of ten federal standards previously included in PURPA. The five new standards relate to net metering, fuel sources, fossil fuel generation efficiency, time-based metering and communications, and interconnection. As with the pre-existing PURPA standards, the Commission may implement the federal PURPA standard or decline to implement such standard, as it deems appropriate. (PURPA Section 111(c)).

The EPACT amended PURPA by adding Standard 15 (Section 111(d)(15)) which provides that electric utilities shall make available, upon request, interconnection service to any customer it serves.

The Standard (PURPA Section 111(d)(15):

Each utility shall make available upon request, interconnection service to any electric consumer that the electric utility serves. For purposes of this paragraph, the term "interconnection service" means service to an electric consumer under which an on-site generating facility on the consumer's premises shall be connected to the local distribution facilities. Interconnection services shall be offered based upon the standards developed by the Institute of Electrical and Electronics Engineers: IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems, as they may be amended from time to time. In addition, agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

Issues

1. **What are the current interconnection practices and policies of each New Hampshire utility?**

   PSNH follows the interconnection practices and policies for Qualifying Facilities (QFs), which were developed by the NH PUC in Dockets DE 80-246, DR 83-62 and later dockets. Those practices and policies have over time been updated to comply with ISO-NE rules. The specific utility-related interconnection requirements used by PSNH are attached. Certain non-QF generators located on the distribution system are also interconnected using these practices and policies. For some non-QFs, ISO-NE procedures and policies must be followed. Net metering projects are covered by state statute (RSA 362-A:9) and PUC Rules Chapter 900.

We believe that the only interconnection polices and procedures that should be considered in this docket are those related to (a) on-site generators (see definition below), (b) QFs and certain non-QFs selling their output to the host utility, and (c) net metering. These facilities generally interconnect with the distribution system at voltages of 34.5 kilovolts or less. They are not covered by the ISO-New England interconnection procedures unless the generators are 5 MWs or greater.

2. **Has the state or the Commission already taken any action that would constitute prior state action under the Standard? For example, do the interconnection provisions in PUC 900 Rules: Net Metering for Customer-Owned Renewable Energy Generation Resources of 25 Kilowatts or less qualify as a comparable standard?**

   Yes. Utilities have been designing, interconnecting, and monitoring interconnection arrangements with QFs, on-site generators, Exempt Wholesale Generators, and net metering customers for over 20 years under the standards developed in the Small Power Producer and Cogenerators dockets (as noted above) and through the Net Metering Rules.

3. **What is an appropriate definition of on-site generator under the Standard?**

   Any generator connected to the utility grid that is behind a customer's retail meter and used only for the customer's needs or which sells power subject to State regulation only.

4. **Should New Hampshire adopt a standard interconnection policy for all utilities? If not, why not? If so, what should the policy be and who should it apply to?**

   Yes, a standard interconnection policy should be in place for all utilities. We believe the Commission has already adopted such a standard policy with respect to QFs and net metering customers as noted in PSNH's response to Issue 1 above.

5. **Should the standard apply to all new on-site generators regardless of size? If not, what are appropriate size limits under the standard? Should the standard apply to existing projects?**

   Interconnection standards should apply to all generators regardless of size. Specific requirements, however, will differ depending upon a number of factors including whether the generator is synchronous or induction, the size of the generator, and the specific circuit to which the generator is connected. PSNH has found generation at the 1 megawatt level is the threshold where three-phase interruption devices along with more sophisticated protection equipment are needed. Generally generators greater than 5 MWs are considered large generators and require more study and more protection requirements.

In addition ISO-NE requires large generators to be studied to ensure they will not cause an adverse effect on the transmission system administered by ISO and also requires these generators to supply more data on the generator status in real-time than data required from smaller generators.

PSNH feels that existing projects should be subject to the same standards. Upon the expiration of existing rate orders or contracts, PSNH reexamines the existing interconnection arrangement and determines whether any upgrades are needed. Projects are then given a reasonable period of time to comply with those new requirements.

6. **What are the best practices for designing effective interconnection standards that balance the needs of utilities, owners of on-site generation and the public?**

   The currents standards are sufficient to balance the needs of generators, utilities and the public.

7. **Review existing New Hampshire procedures and determine whether they encompass IEEE Standard 1547 and whether they are consistent with "best practices" and are "reasonable, and not unduly discriminatory or preferential."**

While PSNH has not formally adopted IEEE Standard 1547, the current interconnection process addresses most of the aspects of the standard. However, as the standard states in its introduction

> "Although this standard establishes criteria and requirements for interconnection, this standard is not a design handbook nor is it an application guideline. This standard provides the minimum functional technical requirements that are universally needed to help assure a technically sound interconnection."

The IEEE Standard 1547 only provides minimal requirements; therefore, the details of implementation should be better defined and left to the individual utility. Because of the nature of each utility's distribution system in New Hampshire, each generator interconnection must be studied for its individual characteristics and specific location. Adopting a general binding criteria would be detrimental to the generator and more so to our customers.

Where PSNH disagrees with a portion of the intent of Standard 1547 is as follows:

> "Any additional local requirements should not be implemented to the detriment of the functional technical requirements of this standard."

Two areas of concern where we agree with the intent but disagree with the details of the Standard are Section 4.4, Islanding, and Section 4.2.3, Voltage. Requiring interconnections to meet the trip point settings in Section 4.2.3 would most likely result in increasing the sensitivity of the projects to remote faults and cause the projects to trip off line in many instances where the current protection schemes allow the project to ride through such faults. PSNH can elaborate on these areas of disagreement in technical sessions or in response to data requests.

Based upon the foregoing, PSNH recommends that, if adopted, IEEE 1547 should be used only as a guide for generation interconnections.

8. **What are the advantages and disadvantages of: (i) adopting the IEEE 1547 interconnection standard; (ii) adopting NARUC's "Model Interconnection Procedures Agreement for Small Distributed Generation Resources" or (iii) applying FERC's interconnection rules (FERC Order 2006) to NH on-site generators?**

(i) See response to #7, above.

(ii) FERC's rules for small generators that are FERC-jurisdictional adopted many of NARUC's concepts. ISO-NE has implemented these FERC rules in its interconnection procedures in Schedules 22 and 23 for these non-State jurisdiction generators; therefore, most of the best practices found in the NARUC's Model Rules are found in the ISO Schedules.

(iii) Generally most on-site generators (as defined above) which are less then 5 MWs are subject only to State jurisdiction and not FERC Order 2006, because they are connected to the distribution system and don't sell into the wholesale market. Because New Hampshire already has interconnection rules and procedures that have worked well over the past 20+ years (and which are similar to FERC's Order 2006) we do not feel the need to subject new generation projects to the added complexity of adopting FERC Order 2006 for all generators.