Informe del oficial examinador - Vistas Públicas del informe "Consideración de los Estándares del Epact 2005: Time Based Metering and Communications Interconection Standards for Distributed Resources"

Sometido a:
Junta de Gobierno, Autoridad de Energía Eléctrica de Puerto Rico

Por:

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18 de Julio de 2007

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Tabla de contenido

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I. Introducción

El Energy Policy Act 2005 (EPAct 2005) del 8 de agosto de 2005 enmendó la Public Utility Regulatory Policies Act (PURPA) a los fines de requerir que las compañías de electricidad consideren cinco (5) distintos estándares.

En cumplimiento con dicho requisito, la Autoridad de Energía Eléctrica de Puerto Rico (AEE) se encuentra en el proceso de evaluación de éstos. Por tal razón, y a los fines únicos de determinar si se adoptan dos (2) de estos cinco (5) estándares, el 1252 y el 1254, la AEE (según se evidencia en la página 1 de su informe *Consideración de los Estándares del Epact 2005: Time Based Metering and Communications Interconection Standards for Distributed Resources)*, nombró comités de trabajo multidisciplinarios y contrató los servicios de EPRI International, para investigar las prácticas contemporáneas relacionadas con el Interconnection Standard for Distributed Resources.

A estos efectos y para claridad del informe, citamos las dos (2) secciones bajo consideración:

La sección 1252 lee:

Time Based Metering and Communications

(A) Not later than 18 months after the date of enactment of this paragraph, each utility shall offer each of its customers classes, and provide individual customers upon customer request, a time based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility costs of generating and purchasing electricity at the wholesale level. The time based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology.

(B) The types of time based rate schedules that may be offered under the schedule referred to in paragraph (a) include, among others:

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i. time of use pricing whereby electricity prices are set for a specific time period on an advance or forward bases, typically not changing more often than twice a year, based on the utility's cost of generating and/or purchasing such electricity at the wholesale level for the benefit of the consumer. Prices paid for energy consumed during these periods shall be pre established and known to consumers in advance of such consumption, allowing them to vary their demand and usage in response to such prices and manage their energy cost by shifting usage to a lower cost period or reducing their consumption overall;

ii. critical peak pricing whereby time of use prices are in effect except for certain peak days, when prices may reflect the cost of generating and/or purchasing electricity at the wholesale level and when consumers may receive additional discounts for reducing peak period energy consumption;

iii. real time pricing whereby electricity prices are set for a specific time period on an advanced or forward basis, reflecting the utility's cost of generating and/or purchasing electricity at the wholesale level, and may change as often as hourly; and

iv. credits for consumers with large loads who enter into pre established peak load reduction agreements that reduce a utility's planed capacity obligations

(C) Each electric utility subject to subparagraph (A) shall provide each customer requesting a time based rate with a time based capable of enabling the utility and customer to offer and receive such rate respectively.

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La sección 1254 reza:

Interconnection

Each electric utility shall make available, upon request, interconnection service to any 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 are offered shall promote current best practices of interconnection for distributed generation, included but not limited to practices stipulated in model codes adopted by associations of states regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential.

Por otro lado, y como requisito mínimo en el análisis de la adopción de estos estándares, la sección 111(b)(1) de PURPA establece y cito:

"After public notice and hearing a state commission's or utilities determination is to be made (a) in writing, (b) based upon findings included in such determination and upon evidence presented at the hearing, and (c) available to the public.[1]

La AEE está obligada a cumplir con la disposición federal antes citada, en la consideración de la determinación de la adopción o no de las secciones 1252 y 1254. Así también por cualquier otra ley estatal aplicable. A estos efectos, y considerando que la sección 1252 antes citada repercute en cierta medida con el proceso establecido en la Ley 21 del 31 de mayo del 1985, y por que esta ley estatal, si se compara con la Ley de Procedimiento Administrativo Uniforme[2] (LPAU), amplía la participación

[1] This appears to allow a range consideration of the federal standard by state commissions and utilities, from a "paper" hearing, for example, where the commission makes a determination based on written filings form interested parties, to a full evidentiary hearing with written testimony from expert witnesses, rebuttals, and a opportunity for cross-examination of the witnesses by the participating parties. Reference Manual and Procedures for Implementation of the PURPA Standards in the Energy Policy Act 2005, pp 8.

[2] En su libro, Derecho Administrativo y Ley de Procedimiento Uniforme, pp. 27, nos dice Demetrio Fernández de la participación ciudadana en la LPAU: Las disposiciones estatutarias aplicables al

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ciudadana[3], el proceso de vista[4] y redacción del informe debe cumplir con lo dispuesto en ésta, especialmente lo aplicable del artículo 3 de la Ley 21, el cual cito:

Artículo 3- Procedimiento para tarifas permanentes

Toda Autoridad, corporación pública u otra instrumentalidad gubernamental análoga que provea servicios públicos básicos y esenciales a la ciudadanía no hará cambios en las tarifas que cobra a sus abonados o usuarios por dichos servicios, a no ser que cumpla con los siguientes procedimientos:

(a) No se harán cambios de tarifas, con carácter permanente, a menos que se celebren vistas publicas debidamente anunciadas en dos (2) periódicos de circulación general en Puerto Rico, con por lo menos quince (15) días de antelación a la fecha de celebración de las mismas, indicando en el anuncio el sitio, la fecha y hora en que se llevara a cabo tal vista, las tarifas en vigor,

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proceso de reglamentación exigen a la agencia administrativa que publique el aviso de notificación de la propuesta reglamentación. La ley no le requiere a las agencias que le provea a las personas interesadas una participación análoga a la del procedimiento de adjudicación. Se le confiere a la agencia la discreción de diseñar el procedimiento para la participación pública en el procedimiento de reglamentación. Solo se le impone a la agencia administrativa que le provea a la ciudadanía "oportunidad para someter comentarios por escrito durante un término no menor de treinta días (30) contados a partir de la fecha de publicación del aviso" (3 L.P.R.A., sec. 2122). La forma, manera y grado de participación del público y la ciudadanía son determinadas por entero por la agencia. Para propósitos de ley el requisito de participación pública se cumple en la medida en que se notifique en el aviso de que la información y el escrito se le someten a la agencia (La ley de Procedimiento Administrativo federal alude a este asunto de la participación de los ciudadanos y de los procedimientos en 5 U.S.C. sec. 553 (C)). La vista pública solo será obligatoria en los casos en que el estatuto orgánico de la agencia lo requiera. La audiencia en el procedimiento de reglamentación no es un derecho constitucional. De celebrase vista oral, el funcionario que la presida viene obligado a preparar un informe para la consideración de la agencia. Dicho informe contendrá un resumen de los comentarios orales expuestos. Puede el funcionario auxiliarse con grabaciones o notas estenográficas.

[3] ...La oportunidad de participación pública faculta la representación vigorosa que de otra manera estará ausente del proceso. La labor de los intereses en juego por parte de la Agencia tiende a restringirlos en la visión porque los diferentes grupos, en esencial los minoritarios, se encuentran inadecuadamente representados o sin representación de clase alguna. Hay algo mas, las agencias a veces se encuentran limitadas, presa por lo intereses que regulan y solo expresan los puntos de vistas de los que regulan. La participación del público en general asegura que la agencia considere todos los puntos de vista. Derecho Administrativo y Ley de Procedimiento Uniforme, Demetrio Fernández, Forum, pp129.

[4] Es imperativo aclarar que el proceso de vista no es de carácter adjudicativo, y aunque algunos deponentes en sus posiciones presentaron casos individuales reales, solamente éstos se consideraron a los efectos de determinar la adopción o no de las secciones 1252 y 1254. Recordando que cualquier petición relacionada a estos casos, debe ser tramitada siguiendo los procedimientos administrativos ordinarios de adjudicación de la agencia.

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las tarifas propuestas o cambios en las tarifas que se proponen adoptar y la fecha de efectividad del propuesto cambio.

(b) La Autoridad pondrá a disposición del público con suficiente antelación a la fecha de celebración de las vistas públicas, los informes o documentos de la agencia apoyando o justificando el propuesto cambio tarifario.

(c) Las vistas públicas ordenadas por este artículo serán presididas por un oficial examinador de reputado conocimiento en la estructura tarifaría de la agencia, designado por la Autoridad para tal efecto. En caso de resultar necesario transferir personal de la agencia para encomendarle la función de servir como oficial examinador durante estas vistas públicas, la persona designada no podrá haber intervenido anteriormente en la determinación del propuesto cambio tarifario.

(d) El oficial examinador escuchará los argumentos de los deponentes y les concederá la oportunidad de presentar testimonio pericial y documental. Dicho funcionario emitirá un informe, que someterá a la Junta de Directores de la Autoridad dentro de los sesenta días siguientes a la fecha que se concluyen las vistas públicas, el cual deberá contener una relación de todas las objeciones, planteamientos, opiniones, documentos, estudios, recomendaciones y cualesquiera otro dato pertinente presentado en la vista, así como conclusiones y recomendaciones. Copia de dicho informe se pondrá a la disposición del público para examen y estudio, debiéndose notificar tal hecho a través de los medios de difusión pública. Cualquier persona interesada podrá presentar por escrito a la Junta de Directores de la Autoridad concernida comentarios al informe, dentro de los diez (10) días siguientes a la fecha en que el mismo haya estado a disposición del público.

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II. Notificación

Cumpliendo con la sección 111(d) de la Ley PURPA y la Ley 21 antes citada, la AEE publicó anuncios en los periódicos el Vocero de Puerto Rico y el Nuevo Día.

1. La certificación de la publicación en el periódico El Vocero de Puerto Rico de los días 22 y 23 de junio de 2007, consta en el testimonio número 76,749 suscrito por Marisol Ramos Miranda el 6 de julio de 2007.
2. La certificación de la publicación en el periódico El Nuevo Día el día 21 de junio de 2007, consta en el testimonio número 65,725 suscrito por Lissette Cortes el 6 de julio de 2007.
3. La certificación de la publicación en el periódico El Nuevo Día el día 22 de junio de 2007, consta en el testimonio número 65,726 suscrito por Lissette Cortes el 6 de julio de 2007.
4. La certificación de la publicación en el periódico El Nuevo Día el día 23 de junio de 2007, consta en el testimonio número 65,727 suscrito por Lissette Cortes el 6 de julio de 2007.
5. Así también la notificación fue publicada en la hoja de internet de la AEE, www.aeepr.com.

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III.Transcripción de las vistas del 9 de julio de 2007

Ver apéndice A

IV. Transcripción de las vistas del 10 de julio de 2007

Ver apéndice B

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V. Informe del oficial examinador

Las vistas públicas se celebraron los días 9 y 10 de julio de 2007, en Ponce y San Juan, Puerto Rico, respectivamente, y según previamente notificado.

La vista del 9 de julio de 2007, se celebró en el salón de actividades de la Guancha, Ave. Santiago de los Caballeros, Sector la Guancha, Ponce, Puerto Rico y comenzó a las 10:00 a.m. y finalizó a las 2:00 p.m. según notificado. A la vista asistió la Autoridad de Energía Eléctrica, representada por el Lcdo. Félix Pérez Rivera, y el Ingeniero Juan F. Alicea, PE, Director del Departamento de Planificación y Estudios de la AEE y la Ing. Sonia Miranda, PE, Jefa de la Division de Planificación y Estudios de la AEE. La participación ciudadana estuvo representada por los doctores Agustín Irrizarry Rivera, PE y Efraín O'Neill Carrillo, PE (el Dr. O'Neill no estuvo físicamente presente), ambos en una ponencia conjunta y representando al Recinto Universitario de Mayagüez y el Ing. Peter W. Sinz, PE. La vista fue presidida por el oficial examinador, ingeniero y licenciado, Edison Avilés Deliz, PE, el cual estuvo asistido técnicamente por el ingeniero Alfredo Huertas del Toro, PE.

La vista del 10 de julio de 2007, se celebró en el Edificio Juan Ruiz Vélez, Ave. Ponce de León, Pda. 16 ½, Santurce, Puerto Rico, comenzó a las 10:00 a.m. y finalizó a las 2:00 p.m. según notificado. A la vista asistió la AEE, representada por el ingeniero Juan F. Alicea, PE, el licenciado Félix Pérez Rivera y la ingeniera Sonia Miranda, PE. La participación ciudadana estuvo representada por[5]: Alan Rivera Ruiz, fundador Asociación Puertorriqueña Energía Verde (APEC); Ing. Gerardo Cosme Núñez, PE; Dr. Albith Colón, PE, y el Ing. Walter Pedreira, PE, representando a Asociación de Consultores y Contratista de Energía Renovable de Puerto Rico (ACONER-PR); Jorge El Koury[6], representando a la Cámara de Comercio de Puerto Rico; Dr. Fernando Abruña, FAIA, representando al Colegio de Arquitectos y Arquitectos Paisajistas de Puerto Rico, al US Green Building Council Caribbean Chapter, y al American Institute of Architects, Puerto Rico Chapter; el Sr. John Miller representando a Alianza Comunitaria y Ambiental en Acción Solidaria (ACAAS); el Ing. Juan A. Pérez González, PE,

[5] Incluimos y analizamos también la ponencia de la Asociación de Industriales de Puerto Rico, quienes a pesar de no estar físicamente en la vista, enviaron por correo electrónico su posición. La ponencia está suscrita por Roberto J. Monserrate Maldonado, Vicepresidente de Asuntos Legales y Legislativos.
[6] El Sr. El Koury no entregó ponencia escrita.

Presidente del Colegio de Ingenieros y Agrimensores de Puerto Rico (CIAPR) junto a los ingenieros Peter W. Sinz, PE y Enrique Siaca Estévez, PE, en representación del CIAPR y el Sr. Héctor Arana. La vista fue presidida por el oficial examinador, ingeniero y licenciado, Edison Avilés Deliz, PE, quien estuvo asistido técnicamente por el ingeniero Alfredo Huertas del Toro, PE.

A. Sección 1252

La posición preliminar de la AEE, según establecida en el informe es que la AEE ya cumple con lo requerido en dicha sección en lo que a clientes comerciales e industriales se refiere, y que en este momento no adoptará la sección 1252 para los clientes residenciales. A estos efectos los deponentes reaccionaron:

1. Relación de todas las objeciones

De un total de 13[7] deponentes, sin incluir a la AEE, 11 entienden igual que la AEE, en el sentido que actualmente existen tarifas basadas en tiempo para el sector comercial e industrial, uno entiende que los requisitos de generación de carga en las tarifas actuales hacen que éstas sean inoperantes, y un deponente no presento posición alguna al respecto. Sin embargo, en lo que a la adopción de el estándar al sector residencial se refiere, de los 13 deponentes, 11 están en desacuerdo con la posición de la AEE, uno está de acuerdo, y otro no asumió postura al respecto.

2. Planteamientos, opiniones, documentos, estudios y recomendaciones de los deponentes

Se incluyen las ponencias de cada uno de los deponentes en el apéndice C.

3. Conclusiones y recomendaciones del oficial examinador

En el informe *Consideración de los Estándares del EPACT 2005: Time Based Metering and Communications Interconnecting Standards for Distributed*

[7] Es necesario aclarar que el Dr. Abruña fue autorizado en su ponencia escrita a representar a tres (3) distintas asociaciones.

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Resources del Departamento de Planificación y Estudios de la AEE, junio de 2007, la AEE se inclina a no adoptar la sección 1252 para tarifa residencial, y entiende que actualmente tiene vigentes estas tarifas para el sector industrial y comercial. La AEE en la página 26 de dicho informe establece, y cito:

“La Autoridad tiene disponible tarifas TOU para Clientes comerciales e industriales desde el 1989 y provee el sistema de medición adecuado para cumplir con esta aplicación. Sin embargo, la Autoridad entiende que no debe adoptar el estándar Time Based Metering and Communications para la clase residencial. Esto debido a que de acuerdo con el comportamiento típico de la clase residencial y la corta duración del periodo fuera de pico de nuestro sistema, entendemos que le resultaría poco práctico y difícil a estos clientes transferir la carga. Además, le podría resultar en una facturación mayor si el cliente no logra hacer transferencias de la carga adecuada. Otras razones para no adoptar este estándar son las siguientes:

1. Seria necesario reemplazar el equipo de medición actual y hacer modificaciones en el sistema de facturación, lo cual resultaría costoso y habría que determinar si esta diferencia en costo se les transfiere a todos los clientes o a los clientes que se acojan a una tarifa de uso.

2. Debido al comportamiento del sistema eléctrico, la diferencia en costos de generación entre los periodos típicos y fuera de pico no es costo efectivo para transferir la demanda de un periodo a otro.

3. Con los datos de factor de carga y la curva de demanda del sistema se puede concluir que la demanda no tiene fluctuaciones considerables con respecto a la demanda máxima durante el periodo de 24 horas en cualquier día del año. Por lo tanto, el transferir carga podría causar un pico de demanda en el periodo fuera de pico”.

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El Reference Manual and Procedures for Implementation of the PURPA Standards in the Energy Policy Act 2005[8], establece distintos parámetros útiles para la toma de decisiones en la adopción o no de los estándares.

Entre los elementos a considerarse para la adopción del estándar 1252 hallamos que la compañía de electricidad debe evaluar y considerar que:

1. Cada tipo de tarifa basada en precio es diferente y puede que no trabaje igual para cada sector de clientes (industrial, comercial y residencial).
2. Que si una tarifa no funciona, no significa que las otras no funcionarán.
3. Que la mayoría de los beneficios de la tarifa basada en tiempo se lograrán solo si los consumidores responden a las señales de cambios en los precios, y cambian su patrón de consumo.
4. Las metas de las tarifas basadas en tiempo están entrelazadas. Algunas metas tienen el efecto de aumentar otras metas, disminuirlas o cancelarlas.
5. Las tarifas basadas en tiempo pueden ser apropiadas para ciertos consumidores o compañías de electricidad en determinado lugar, y la decisión podría ser que la tarifa basada en tiempo es apropiada para ciertos sectores o compañías de electricidad, pero no para otras.

En nuestro País, ya que no existe una agencia reguladora, la decisión o la autoridad de determinar si es adecuada una tarifa basada en tiempo recae sobre la AEE. A estos efectos es la AEE quien juzga los costos y beneficios de la tarifa basada en tiempo, y es quien determina si la implementación resulta en facturas mayores a las actuales. Si la factura a base de tiempo de uso es mayor, entonces se puede argumentar que el precio de los costos promedio, tarifa actual en el sector residencial, provee mayores beneficios. Aumentos en la factura podrían resultar en problemas para mantener una tarifa basada en tiempo de uso.

[8] Este es un manual diseñado para ayudar a las Comisiones reguladoras o a las compañías de electricidad en la consideración de los nuevos estándares federales que son parte del Energy Policy Act of 2005. El manual es auspiciado por American Public Power Association (APPA); Edison Electric institute (EEI); National Association of Regulatory Utility Commisioners (NARUC) y el National Rural Electric Cooperative Association (NRECA), y fue preparado por Kenneth Rose y Kaarl Meeusen, en marzo 22, 2006.

G00014

Por tal razón, la AEE debe preguntarse y contestar por separado, la aplicabilidad de la tarifa basada en tiempo de uso para los distintos sectores, esto es industrial, comercial y residencial.

Una vez identificados los sectores, un próximo paso seria determinar las metas que esperan lograr a base del uso de tarifa basada en tiempo de uso. Las metas podrían incluir, sin limitarse a:

1. Reducir la demanda total
2. Reducir la demanda pico
3. Mitigar el precio relacionado a la demanda pico
4. Aumentar la confiabilidad del sistema
5. Aumentar la eficiencia en el uso de su capacidad
6. Disminuir la factura por consumo
7. Disminuir el costo de la energía
8. Reducir las emisiones.

Estas metas interactúan, por tal razón el logro de una de éstas como meta principal, podría afectar negativamente otra de la metas. En el análisis la compañía de electricidad debe conocer sus clientes. Debe estar al tanto del comportamiento de estos, y su disponibilidad de ajustar su consumo. Debe conocer la composición de sus clientes (industrial, comercial y residencial), la disposición de cada sector a aceptar riesgos en el precio, y que nivel de riesgo está dispuesto a aceptar, lo que determinará la respuesta general a fluctuaciones en precio. En términos generales, los clientes residenciales tienen una preferencia a menos riesgo. Los clientes comerciales e industriales tienden a ser más responsivos a precios dinámicos. Grandes clientes o consumidores industriales podrían tener mayores opciones disponibles para disminuir la carga, y podrían también tener disponible generación en sitio. Los clientes industriales podrían beneficiarse de tarifas basadas en tiempo, aún cuando no reduzcan su carga, pero la mueven de los períodos pico.

La agencia debe en su análisis considerar los beneficios de la tarifa a base de tiempo. Los beneficios puede que incluyan:

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1. Aumento de confiabilidad
2. Reducción en los precios de la energía y/o facturas reducidas para los clientes
3. Reducción en los costos operacionales de la compañía de electricidad
4. Beneficios ambientales de la reducción del consumo eléctrico

Sin embargo, es necesario señalar que los beneficios solo se logran si en efecto los consumidores reducen su demanda en respuesta a los cambios de precio.

Por otro lado, también el análisis debe considerar los costos asociados a la tarifa. Los costos podrían incluir:

1. Inversión en metros y cualquier otra infraestructura, y gastos administrativos asociados.
2. Tecnología y mejoras en el sistema de colección de data
3. Apoyo para tecnología y análisis de data
4. Educación del consumidor y servicio adicional al cliente
5. Costos a los consumidores en inconvenientes, riesgo en los cambios de precio, o interrupción de producción

Antes de implementar una factura basada en tiempo de consumo, es necesario determinar quien absorberá los costos asociados a ésta. Los metros tradicionales no tienen la capacidad técnica necesaria para la implementación de facturas basadas en tiempo. Por tal razón será necesario, o mejorarlos, si es posible, o sustituirlos por unos con la tecnología apropiada para dicha aplicación. Indiscutiblemente habrá costos relacionados con el reemplazo de los metros, el cual dependerá en gran medida en el método utilizado para el reemplazo, la densidad poblacional, metros por sitio, entre otros factores. Así también, además de la inversión antes señalada, será necesario invertir en infraestructura adicional, dependiendo de la tecnología de comunicación y recopilación de data seleccionada.

La compañía de electricidad deberá considerar los costos administrativos relacionados con la implementación y mantenimiento de la tarifa. El costo de recopilación de data puede aumentar por el volumen, pero así también los gastos asociados a la

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recopilación de la información podrían disminuir debido a la capacidad de lectura remota y automática.

Así también es necesario educar e informar a los clientes. Esto para el beneficio de todas las partes, tanto para la compañía de electricidad como el consumidor. La compañía debe analizar la viabilidad de entregar la información a los clientes vía un servicio interactivo de Internet, de forma tal que puedan monitorear los cambios de precios, por lo que posiblemente aumente el gasto administrativo asociado a problemas del cliente relacionados al cambio de entrega de información.

Sin embargo, es importante señalar que los consumidores residenciales generalmente están expuestos a costos diferentes de los demás sectores de la industria eléctrica. Los riesgos asociados podrían mitigarse modificando el patrón de consumo. Pero para que una tarifa a base de tiempo pueda ser exitosa, el consumidor tiene que tener la capacidad de monitorear y cambiar su patrón de consumo en respuesta a los cambios en el precio. El continuo monitoreo tiene un costo asociado, con el inconveniente, que el consumidor podría no poder hacer lo que desee cuando lo desea (por ejemplo, prender el aire acondicionado a mitad de noche), u obligársele a hacer lo que quiere, pero cuando el no quiere (por ejemplo lavar ropa durante la media noche, mientras intenta dormir). Por tal razón, en el ámbito residencial, el ahorro, si alguno, asociado a la tarifa de tiempo, debe ser mayor a cualquier gasto incurrido por los inconvenientes típicamente asociados, y antes explicados. A estos efectos si el consumidor ve los inconvenientes asociados como un obstáculo mayor que el posible ahorro, la tarifa posiblemente no sea viable. Los beneficios y costos asociados a cada sector deben ser utilizados para determinar la viabilidad de su implementación. Es un requisito mínimo que los beneficios superen los costos.

Con esto en mente, hemos evaluado detenidamente el informe de la AEE, a la luz inclusive de las preocupaciones de Ing. Gerardo Cosme, PE[9]; el Dr. Agustín Irrizarry[10], PE; y el Presidente del CIAPR, el Ing. Juan A. Pérez, PE[11], sobre la data utilizada por la AEE en su análisis, pero sin perder de perspectiva que es la AEE quien en efecto tiene experiencia, competencia técnica, conocimiento especializado y juicio sobre dicha data.

[9] Expresa el ingeniero en la página 3 de su deposición: "Finally, the PREPA document does not provide enough information to justify their reluctance to adopt EPAct 2005, sec. 1252, and their assessment is based on guesses".

[10] Expresa el Dr. Agustín Irrizarry en su ponencia: "En realidad no podemos evaluar adecuadamente estos cómputos pues no tenemos acceso alguno a los datos usados para hacer los cómputos".

[11] En realidad no se pueden evaluar adecuadamente sus alegadas conclusiones, pues no tenemos acceso alguno a los datos usados para hacer los supuestos cómputos.

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A estos efectos, concluimos sobre el particular, que encontramos que la data utilizada, el procedimiento, y las conclusiones de la AEE son razonables, y por lo tanto no son caprichosas y mucho menos arbitrarias.

En términos generales, entendemos que la AEE ha cumplido con las guías establecidas en el Reference Manual and Procedure for Implementation of the PURPA Standards in the Energy Act 2005, y los propósitos de PURPA, esto es:

1. La conservación de energía suplida por las compañías de electricidad
2. Optimizar la eficiencia en el uso de las instalaciones y recursos de las compañías de electricidad
3. Establecer tarifas equitativas para los consumidores de electricidad

Sin embargo, como mencionó el Dr. Agustín Irrizary en su ponencia, y cito:

"La historia de la humanidad esta llena de ejemplos en donde países, personas u organizaciones han estado en momento cruciales de decisión que marcaron su destino. Lo triste en muchos casos, es no darse cuenta en esos momentos de la importancia de los mismos. Puerto Rico enfrenta un momento crucial en el desarrollo de sus recursos energéticos. Salieron del país en el año 2006 sobre $6,000 millones para la compra de combustibles fósiles (estudio del Dr. Alameda, RUM). En PR, donde no tenemos ningún combustible fósil, debemos explorar todas las posibles alternativas y evaluarlas no solo en términos de costo efectividad, sino también en términos ambientales y sociales".

Y aunque es un hecho que la AEE recientemente está en el proceso de terminar la implementación de metros de lectura remota por medio de TWACS (Two Way Automatic Communication System), los cuales no tienen la capacidad requerida en la sección 1252, lo cierto es que con toda posibilidad al adoptarse la reglamentación para la aplicación de la sección 1254, los metros serán del tipo inteligente. Así también, y dentro de los próximos meses, al evaluarse la adopción o no de la sección 1251, será necesario para dicha aplicación metros inteligentes. Vemos pues una grandiosa oportunidad[12], en la cual, y de aprobarse la sección 1251, la AEE pueda actualizar la

[12] Siguiendo la petición del Dr. Agustín Irrizarry,PE, el cual expresa: "Sugiero que no se abandone la consideración de medición avanzada por los beneficios de conservación y mejoras al servicio que recibe el cliente que esta medición ***pueda*** (énfasis nuestro) traer. Recomendamos reevaluar esta medida, no

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data y conclusiones del informe, a través de un plan o proyecto piloto, en el cual se establezca una tarifa a base de tiempo residencial. Esta recomendación en esencia responde a que creemos que el cliente que implemente las secciones 1254 y 1251, de ésta adoptarse, es un cliente distinto al cliente residencial tradicional. Este cliente es uno dispuesto a modificar su comportamiento de consumo, y a aceptar riesgos en el precio y por lo tanto a acogerse a una tarifa residencial basada en tiempo de uso, aún en casos en que el beneficio puede ser menor al costo asociado. Dependiendo del resultado del plan piloto, el Departamento de Planificación y Estudios, podrá determinar a ciencia cierta la viabilidad de éste a mayor escala.[13]

A estos efectos, acogemos y recomendamos la posición del informe de la AEE, con la modificación antes mencionada.

B. Sección 1254

La posición preliminar de la AEE, según establecida en el informe es que la AEE adopte la sección 1254 según redactada, y que se reglamente de acuerdo a las guías de NARUC. A estos efectos los deponentes reaccionaron:

1. Relación de todas las objeciones

La mayoría de los deponentes están de acuerdo con la posición de la AEE, excepto uno, quien no estableció su posición al respecto.

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solo desde el punto de vista económico, sino también considerando los beneficios ambientales y sociales de esta tecnología".

[13] Esta recomendación está a tono con lo presentado por el Dr. Albith Colon, PE y el Ing. Walter Pedreira, PE, de ACONER-PR, quienes expresaron y cito: "*ACONER-PR recomienda la adopción del estándar 1252, tal y como lo recomienda la División de Estudios y Planificación de la AEE en su informe publicado en junio 2007. En el informe la AEE no recomienda que se aplique en este momento a nivel residencial, por los costos asociados de infraestructura. El cual penalizaría basado en costos de instalación de nuevos equipos o reemplazo de estos equipos, tanto al usuario como a la empresa de utilidad o AEE. Sin embargo, la AEE y ACONER-PR sí recomiendan que inicialmente su utilización sea a tarifas industriales y comerciales. Finalmente, en clientes con tarifas basadas en el estándar 1252 a través de inyección energética por Fuentes Renovables, se pudiera observar un beneficio tanto para el cliente como para la red AEE, con este tipo de tarifa. ACONER-PR favorece la implantación del estándar a nivel residencial en un futuro cercano (posiblemente 3 a 5 años) una vez se pueda implementar tecnologías costo-efectivas o medidas, subsidios y/o financiamiento que permita absorber los costos para tanto los residenciales como para la AEE. Nuestra organización está totalmente de acuerdo con la adopción de este estándar como un medio importante para ayudar "a fomentar el desarrollo de alternativas de energía renovable".*

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2. *Planteamientos, opiniones, documentos, estudios y recomendaciones de los deponentes*

Se incluyen las ponencias de cada uno de los deponentes en el apéndice C.

3. *Conclusiones y recomendaciones del oficial examinador*

Recomendamos adoptar la sección 1254, la cual incluye el estándar 1547 de la IEEE, así también (aunque reconocemos que está fuera del alcance de este informe, no podemos obviar la petición hecha por los deponentes durante la vista pública a la AEE), que y como parte de la reglamentación de éste, se incorpore el NARUC Model Interconection Procedures and Agreement for Small Distributed Generation Resources, y según expresado en las recomendaciones hechas por el CIAPR, que se considere en el proceso de reglamentación:

1. Los requerimientos de medición para la interconexión, así como el precio y demás términos y condiciones para la compra del excedente de electricidad producido por los generadores distribuidos.
2. La posibilidad de establecer el arbitraje como alternativa para la solución de disputas sobre interconexión, utilizando el recurso de expertos técnicos o "Technical Master", sugeridos en NARUC.
3. La adopción de un procedimiento expedito de interconexión para facilidades de generación pequeñas certificadas no mayores de 10 KW y basadas en inversores que ha adoptado el FERC.
4. La adopción de metros inteligentes como parte del estándar o reglamentación de interconexión.

En resumen acogemos lo concluido por la AEE en la página 27 de su informe, y citamos:

"La Autoridad entiende que debe adoptar un estándar de interconexión que cumpla con lo establecido en EPAct 2005. El mismo requerirá que los generadores a interconectarse cumplan con las normas, reglamentos y estándares aplicables, incluyendo el estándar IEEE 1547.

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Los procedimientos y acuerdos incluidos en el reglamento deberán adoptar las mejores prácticas contemporáneas de interconexión. El reglamento de interconexión considerará particularidades del sistema eléctrico de la Autoridad. Además, recomendamos que al diseñar los procedimientos y acuerdos de interconexión, la Autoridad considere los modelos establecidos en las guías de NARUC. No obstante la Autoridad deberá armonizar los procedimientos establecidos en estas guías a sus procesos administrativos".

A estos efectos, en términos generales, entendemos que la AEE ha cumplido con las guías establecidas en el Reference Manual and Procedure for Implementation of the PURPA Standards in the Energy Act 2005, y los propósitos de PURPA, tanto para la evaluación de la sección 1252 y 1254, esto es:

1. La conservación de energía suplida por las compañías de electricidad
2. Optimizar la eficiencia en el uso de las instalaciones y recursos de las compañías de electricidad
3. Establecer tarifas equitativas para los consumidores de electricidad

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Apéndice A

C00023

ORIGINAL

EN EL ESTADO LIBRE ASOCIADO DE PUERTO RICO
AUTORIDAD DE ENERGÍA ELÉCTRICA DE PUERTO RICO
SAN JUAN, PUERTO RICO

TRANSCRIPCIÓN DE VISTA PÚBLICA SOBRE:

LOS ESTÁNDARES DEL EPAct 2005
TIME-BASED METERING AND COMMUNICATIONS E INTERCONNECTION STANDARDS FOR DISTRIBUTED RESOURCES
SECCIONES 1252 Y 1254

LUGAR:	SALÓN DE ACTIVIDADES EN LA GUANCHA AVE. SANTIAGO DE LOS CABALLEROS SECTOR LA GUANCHA PONCE, PUERTO RICO
OFICIAL EXAMINADOR:	ING. Y LCDO. EDISON AVILÉS DELIZ
FECHA:	9 DE JULIO DE 2007
HORA CITADA:	10:00 AM
HORA COMIENZO:	10:00 AM
HORA FINALIZA:	2:00 PM

MARIBEL RIVERA SÁNCHEZ
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COMPARECENCIA

ING. Y LCDO. EDISON AVILÉS DELIZ

OFICIAL EXAMINADOR

ING. ALFREDO HUERTAS DEL TORO

ASESOR TÉCNICO

ING. JUAN F. ALICEA FLORES

LCDO. FÉLIX E. PÉREZ RIVERA

ING. SONIA MIRANDA VEGA

POR LA AUTORIDAD DE ENERGÍA ELÉCTRICA

DR. AGUSTÍN IRIZARRY RIVERA

POR EL DEPARTAMENTO DE INGENIERÍA Y COMPUTADORAS

DEL RECINTO UNIVERSITARIO DE MAYAGÜEZ

ING. PETER SINZ

EN SU CAPACIDAD PERSONAL

SRA. MARIBEL RIVERA SÁNCHEZ

TAQUÍGRAFA DE RÉCORD

C00026

INTRODUCCIÓN

OFICIAL EXAMINADOR:

Buenos días a todos los presentes. Hoy es 9 de julio del 2007. Yo soy el ingeniero y licenciado Edison Avilés, nombrado por la Autoridad de Energía Eléctrica para ser el Oficial Examinador de estas vistas. Me acompaña a mi izquierda el ingeniero Alfredo Huertas, quien es mi Asesor en cualquier aspecto técnico, ya sea durante la vista o en el proceso de redacción del informe después de celebrada la vista. Cumpliendo con el debido proceso de ley en estos procedimientos, estas vistas fueron notificadas en dos distintos periódicos de circulación general, según consta en las afidávits 76,749 y 65,725. La afidávit 76,749 es del Periódico El Vocero y está suscrita por Marisol Ramos Miranda, y lee: "Yo, Marisol Ramos Miranda, habiendo prestado el juramento debido, declaro lo siguiente: Que soy Supervisora de Cuentas a Cobrar del Periódico El Vocero de Puerto Rico, el cual se publica en San Juan, Puerto Rico, y que en las ediciones de este mismo diario correspondiente a los siguientes días: 22 y 23 de junio de 2007, se dio publicidad al Aviso expedido

000027

por la Autoridad de Energía Eléctrica sobre el asunto arriba mencionado y copia de ésta se une al presente affidávit para que forme parte del mismo, San Juan, Puerto Rico, julio 16, 2007, Marisol Ramos Miranda". La affidávit 65,725, que es del Periódico El Nuevo Día y está suscrita por Lissette Cortés, y lee: "En el... Autoridad de Energía Eléctrica, Aviso sobre Vistas Públicas a celebrarse en Ponce y San Juan, para el proceso de Energy Policy Act 2005. Afidávit: Yo, Lissette Cortés, habiendo prestado el debido juramento, declaro: Que soy Coordinadora de Diagramación y Ventas de El Nuevo Día, que se publica en Guaynabo, Puerto Rico. Que en las ediciones de este periódico correspondiente a los días 21 de junio del 2007 se dio publicidad al edicto expedido por el ingeniero Jorge A. Rodríguez, Director Ejecutivo en el caso arriba mencionado y copia del cual se une a la presente affidávit para que forme parte del mismo. En Guaynabo, Puerto Rico, 6 de junio del 2007, suscrito Lissette Cortés." Así también, dichas notificaciones están en la hoja cibernética de la de la Autoridad de Energía Eléctrica. Ambas afidávits se hacen formar parte del expediente

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administrativo. Estas vistas se celebran para cumplir con lo dispuesto en el Energy Policy Act 2005, el cual le requiere a la Autoridad de Energía Eléctrica la celebración de vistas públicas con la finalidad de determinar si se adoptan o no los siguientes estándares: Time-Based Metering and Communication, Interconnection Standard for Distributed Resources, que son básicamente las Secciones 1252 y 1254 de la Ley EPACT. Como previamente notificado, estaremos aceptando ponencias escritas hasta mañana, 10 de julio del 2007. Las personas a deponer durante el día de hoy les recuerdo que, según previamente establecido, el tiempo para deponer es de quince minutos, con la salvedad que como Oficial Examinador, y dependiendo las circunstancias particulares de cada vista, me reservo la potestad de extender dicho tiempo a petición de parte. Les recuerdo que de tener teléfonos celulares deben tenerlos en el modo silencioso y, en el caso de tener que atender asuntos a través de éste, lo hacen fuera del salón. Finalmente, aclaro que estas vistas son para reaccionar al Informe "Consideración de los Estándares de EPACT2005, Time-Based Metering and

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Communication, Interconnection Standard for Distributed Resources" preparado por la División de Planificación y Estudios, junio 2007. Y como norte los propósitos de la Ley PURPA, promover la conservación de energía que proveen las compañías de electricidad a optimizar la eficiencia en el uso de los... de las compañías de electricidad, de instalaciones y de sus recursos y establecer tarifas equitativas para los consumidores de electricidad. Nuevamente, buenos días a todos. Tenemos hasta el momento tres deponentes. Vamos a comenzar por el ingeniero Juan F. Alicea Flores, en representación de la Autoridad de Energía Eléctrica.

PONENCIA DE LA AUTORIDAD DE ENERGÍA ELÉCTRICA

LCDO. FÉLIX E. PÉREZ RIVERA:

Muy buenos días. Para fines de récord, comparece en la mañana de hoy el licenciado Félix E. Pérez Rivera, Director Asociado de la Autoridad de Energía Eléctrica, Asuntos Jurídicos. Buenos días al Honorable Oficial Examinador, a su distinguido Asesor y a todos los visitantes que están hoy en vistas públicas. Como parte de nuestra comparecencia está presente el ingeniero Juan F.

C00030

Alicea Flores, Director de Planificación y Protección Ambiental, quien va a ser el portavoz de la Autoridad de Energía Eléctrica en estas vistas públicas. Se encuentra, también, la ingeniero Sonia Miranda, quien es Jefa de la División de Planificación y Estudios de la Autoridad de Energía Eléctrica. También, se encuentran en sala varios funcionarios que colaboraron en la preparación de la ponencia que va a hacer en la mañana de hoy, el señor... el ingeniero Alicea Flores, a quien, pues, la Autoridad de Energía Eléctrica agradece la colaboración de los otros funcionarios. Sin más preámbulos, dejamos con usted al ingeniero Alicea Flores. Ah, queremos aclarar para fines de récord que le habíamos entregado copia al Honorable Examinador de la affidávit que hizo para la Autoridad de Energía Eléctrica, El Nuevo Día, con relación al anuncio publicado el 29 de junio de 2007. También, nosotros publicamos el Aviso de estas vistas públicas en dicho periódico, El Nuevo Día, para el 22 de junio de 2007 y el 23 de junio de 2007. Tenemos las afidávits aquí, por un error involuntario, pues le dimos solamente del 21 de junio de 2007, pero tenemos los otros dos avisos,

000031

los dos anuncios que se hicieron los dos días, así que tenemos para entregarle al Honorable Examinador.

OFICIAL EXAMINADOR:

Muchas gracias al Licenciado por la aclaración. Que conste en récord que la Autoridad de Energía Eléctrica oportunamente publicó en El Nuevo Día ...[ininteligible]... por mí sino además el 22 y 23 de junio de 2007 en el periódico El Nuevo Día, y el 22 y 23 de junio en el periódico El Vocero. Muchas gracias. Adelante, Ingeniero.

ING. JUAN F. ALICEA FLORES:

Buenos días al distinguido Oficial Examinador y a su Asesor. Mi nombre es Juan F. Alicea Flores. Soy Ingeniero y Director de Planificación y Protección Ambiental y comparezco a estas vistas en representación del ingeniero Jorge A. Rodríguez Ruiz, Director Ejecutivo de la Autoridad de Energía Eléctrica de Puerto Rico. Comparecemos para presentar la posición de la Autoridad con relación a dos de los estándares establecidos en el Energy Policy Act del 2005, el cual enmendó la ley federal Public Utility Regulatory Policies Act, mejor conocida como PURPA. Estos estándares son Time-

Based Metering and Communications e Interconnection Standard for Distributed Resources. Es relevante expresar que nuestra ponencia está fundamentada en el Informe "Consideración de los Estándares de EPACT 2005: Time-Based Metering and Communications Interconnection Standards for Distributed Resources", que estuvo disponible a todo el público en las oficinas comerciales que fueron informadas en el Aviso de estas vistas públicas que publicamos en varios periódicos de circulación general de Puerto Rico. Así también, está disponible en una dirección de Internet que informamos en dicho aviso. La Autoridad debe determinar si implanta los estándares en Puerto Rico para lograr los propósitos de PURPA. Éstos son: promover la conservación de energía que proveen las compañías de electricidad, optimizar la eficiencia en el uso de instalaciones y recursos de las compañías de electricidad y establecer tarifas equitativas para los consumidores de electricidad. La Autoridad tomará su determinación respecto a la adopción de estos estándares, conforme a la información que se presente en estas vistas y las recomendaciones de este Oficial Examinador. En primer lugar,

explicaremos el estándar Time-Based Metering and Communications. El propósito de este estándar es proveer a todas las clases de clientes y a clientes individuales, según soliciten, tarifas cuyo cargos varíen durante los diferentes períodos de tiempo y reflejen la diferencia, si alguna, en los costos en que incurra la compañía de electricidad en generar y comprar energía. El EPACT05 menciona ejemplos de cuatro tipos de tarifas, éstas son: Tiempo de Uso o TOU, Critical Peak Pricing (CPP), Real Time Pricing, (RTP) y créditos para clientes con carga. Las tarifas en las cuales los precios varían dependiendo del precio en el que el cliente usa la energía tienen como propósito proveer señales de precio para que éstos decidan cuándo consumir la electricidad. Esto podría resultar en reducciones en la demanda en horas en las cuales producir la energía es más costosa y, de esta manera, también aumenta la confiabilidad del sistema. Además, esto podría reducir la necesidad de añadir al sistema de generación unidades que se utilicen en períodos de demanda alta, tales como las turbinas a gas. Según PURPA, las tarifas basadas en tiempo deben ser costo efectivas, esto significa que los beneficios

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que recibe a largo plazo tanto la compañía de electricidad como los clientes excedan los costos asociados con la implantación de estas tarifas. Esto hace necesario que al considerar adoptar este estándar se evalúen los costos en que tendría que incurrir la compañía de electricidad. Algunos de éstos son: inversión en medidores y otra infraestructura para recopilar datos, costos administrativos, adiestramiento técnico a los empleados para analizar la información y cambios en programación para facturar a los clientes. Los costos relacionados en el procesamiento de datos pueden aumentar debido al volumen de la información. También, se deben considerar los costos administrativos para implementar y promocionar la tarifa basada en tiempo y educar a los clientes. Los medidores tradicionales no tienen la capacidad requerida para que las compañías de electricidad implementen tarifas basadas en tiempo. Los medidores inteligentes pueden registrar y almacenar el consumo de energía de clientes por períodos de tiempo. Con esta información se puede facturar a los clientes con tarifas basadas en tiempo. Por lo tanto, la

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compañía de electricidad tendría que incurrir en costos para la adquisición e instalación de medidores nuevos. Estos costos dependen de la tecnología del metro, de la cantidad de medidores a adquirir y del tipo de tarifa basada en el tiempo que se adopte. La Autoridad está en el proceso de completar la instalación de medidores de lectura remota por medio de TWACS (Two Way Automatic Communication System) para todos los servidores de distribución secundaria. Los medidores de TWACS no poseen memoria para almacenar la información del consumo y demanda por período de tiempo. Por lo tanto, la Autoridad no tiene medidores capaces de agrupar el consumo del cliente por período de tiempo para los servicios a voltaje de distribución secundaria. Sin embargo, existen en el mercado medidores con esta capacidad, pero son más costosos que los medidores utilizados actualmente. Cabe señalar que en la mayoría de las ocasiones los clientes deben alterar su patrón de consumo para beneficiarse de las tarifas basadas en tiempo. La acogida de estas tarifas depende grandemente de que los ahorros que obtiene el cliente excedan los costos e inconvenientes en que tienen que incurrir

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para cambiar su patrón de consumo. La Autoridad tiene disponible tarifas de tiempo de uso para las clases de servicio comercial e industrial en su estructura tarifaria. Esto debido a que los clientes comerciales e industriales tienen más oportunidad de transferir parte de su carga y modificar su patrón de consumo. En nuestro análisis graficamos la curva de demanda para definir cuáles serían los patrones de tiempo pico y fuera de pico de nuestro sistema actual. Ambas gráficas están posteadas aquí, a nuestra izquierda. La gráfica de demanda total del sistema muestra que no hay variaciones significativas en la demanda en un período de 24 horas. Además, analizamos qué porción de la generación se suple con unidades base y de unidades pico. De este análisis surge que la demanda de lunes a viernes, entre 12:00 de la medianoche y 9:00 a.m., se suple con unidades base, por lo que ese período se puede clasificar fuera de pico. El resto del tiempo en los días de la semana es período pico, el cual se suple con unidades base y unidades pico. Los fines de semana se pueden clasificar como períodos fuera de pico, con excepción de entre las 7:00 p.m. y las 12:00 de la

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medianoche. También, estudiamos el comportamiento de la clase residencial y cómo ésta afecta la curva de demanda del sistema. En el análisis determinamos que la demanda máxima de los clientes residenciales ocurre dentro del período pico del sistema de la Autoridad, o sea, aproximadamente entre 7:00 de la noche y 12:00 de la medianoche. Al igual que la curva del sistema, en los fines de semana se observa un aumento en la demanda de 7:00 p.m. hasta las 12:00 de la medianoche. Utilizamos modelos matemáticos para calcular el precio promedio de la generación total para los períodos pico y fuera de pico del año 2009. Los resultados del análisis indican que la diferencia en costo entre los períodos es mucho menor de 1 centavo, que fluctúa entre .15 centavos y .47 centavos kilovatio hora. La razón principal que propicia que esta diferencia no sea significativa es la mejora en la eficiencia de las unidades pico, lo cual reduce los costos de producción. Algunas de éstas son: la conversión de Cambalache a un Ciclo Combinado, el aumento en capacidad y eficiencias de las turbinas de gas de Mayagüez y la adición al sistema del Ciclo Combinado de San Juan (Repowering) y el uso

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de gas natural en el Ciclo Combinado de Aguirre. Como resultado de esta evaluación la Autoridad entiende que no debe adoptar el estándar Time-Based Metering and Communication para la clase residencial. La razón principal para que la Autoridad no adopte ese estándar para los clientes residenciales es que, de acuerdo con el comportamiento típico de la clase residencial y la corta duración del período fuera de pico, entendemos que a los clientes residenciales les resultaría poco práctico y difícil transferir la carga. Si el cliente no puede transferir la carga, la tarifa podría resultarle más costosa que una tarifa basada en costo promedio. Además, la demanda del sistema no tiene fluctuaciones considerables con respecto a la demanda máxima durante períodos de 24 horas en cualquier día del año. Por lo tanto, el transferir cargas podría causar un pico de demandas en el período fuera de pico. Otra razón para no adoptar este estándar es que la diferencia en costos de generación entre los períodos pico y fuera de pico no justifican la transferencia de demanda de un período al otro. Además, la necesidad de remplazar el equipo de

medición actual y modificar el sistema de facturación resultaría en un aumento en costos que revierte al cliente. Varias compañías en los Estados Unidos también recomendaron no adoptar ese estándar para la clase residencial. Estudios indican que algunas compañías tienen disponibles tarifas basadas en tiempo para clientes residenciales, pero éstas no tienen mucha acogida. La Autoridad continuamente realiza estudios para evaluar posibles alternativas tarifarias y podría considerar la viabilidad de este tipo de tarifa para los clientes residenciales en el futuro. PURPA Sección 1254-Interconnection Standards for Distributed Resources. El segundo estándar que discutiremos es el de interconexión del EPACT05. El mismo establece que la compañía de electricidad deberá ofrecer servicios de interconexión a generadores localizados en los predios de los clientes al sistema de distribución eléctrica. Éste indica que estos servicios estarían basados en el estándar IEEE 1547 del Institute of Electrical and Electronics Engineers. Además, los acuerdos y procedimientos que se establecerán deberán incorporar las mejores prácticas actuales de

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interconexión, incluyendo las prácticas adoptadas por los modelos de interconexión de las asociaciones de agencias reguladoras estatales. Estos deberán ser justos y razonables y no discriminatorios o preferenciales. Durante la última década el tema de interconexión de generadores al sistema de distribución cobró fuerza en las compañías de electricidad a nivel nacional. Esto se debe, en parte, al desarrollo de las tecnologías de generación y protección utilizadas. Además, el desarrollo de estándares de interconexión por parte de varios estados pioneros, así como la redacción de modelos de interconexión por parte de entidades reguladoras, contribuyeron al crecimiento de los estándares de interconexión en los Estados Unidos. Recientemente el EPACT05, con su estándar de interconexión, aumentó la exposición del tema de interconexión a nivel nacional al requerir a las compañías de electricidad considerar la adopción del mismo. Entre los estados pioneros en el tema de interconexión está California, New York y Texas. Éstos tuvieron como meta desarrollar estándares de interconexión que establecieran una metodología

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uniforme para permitir la interconexión de sistemas de generación de manera segura y confiable. A pesar de que estos Estados realizaron procesos independientes para establecer sus estándares de interconexión, los resultados de los mismos fueron muy similares. De igual manera, entidades nacionales reguladoras desarrollaron modelos de interconexión que incorporan algunas de las prácticas incluidas en los estándares ya establecidos. A mayo del 2007, aproximadamente veinticuatro de los Estados han incorporado algún tipo de estándar de interconexión, según el Interstate Renewable Energy Council. Estos estándares, por lo general, consideran los aspectos técnicos, administrativos y legales aplicables a la interconexión. La Autoridad, al considerar la implantación de estándares de interconexión, debe evaluar los requisitos técnicos, administrativos y legales. Los requisitos técnicos aseguran que la interconexión de los generadores no afectará adversamente la confiabilidad del sistema eléctrico, así como la seguridad tanto del sistema como de sus empleados y sus clientes. Los requisitos administrativos definen los

procedimientos y trabajos necesarios para lograr la interconexión. Los requisitos legales establecen los términos contractuales del acuerdo de interconexión. Como parte de la evaluación, la Autoridad examina los efectos de interconectar generadores a su sistema de distribución eléctrica. La configuración del sistema de distribución de la Autoridad es radial. Éste no está diseñado para incorporar fuentes de generación o almacenamiento de energía eléctrica externos. Por esto, la interconexión de generadores al sistema de distribución puede causar problemas de seguridad, confiabilidad y de operación en el sistema. Entre éstos se encuentra la formación de islas eléctricas, efectos adversos a los sistemas de protección, sobrevoltajes, fluctuaciones de voltajes, inyección de corriente harmónica, parpadeos y resonancia. Todo estándar de interconexión tiene que tomar en cuenta los efectos adversos de interconexión... efectos adversos de interconectar generación para garantizar la seguridad y confiabilidad del sistema eléctrico. El EPACT05 establece que los estándares de interconexión que adopten las compañías eléctricas

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deben estar basados en el estándar IEEE. Éste provee una metodología uniforme para la interconexión de generadores al establecer los requisitos técnicos mínimos para lograr una interconexión segura y confiable al sistema de distribución eléctrica. El mismo señala cómo los generadores operarán bajo condiciones normales y ante disturbios en el sistema de distribución. Además, incluye los requisitos y especificaciones de pruebas a los que se someterán estos equipos. El estándar no incluye todos los aspectos técnicos que deben evaluarse para su cumplimiento. Por ejemplo, el estándar no establece límites de contribución de corrientes de corto circuito que garantice que estos sistemas no afecten adversamente el funcionamiento de los equipos de protección. Tampoco considera la configuración de los transformadores de interconexión utilizados o los efectos de resonancia que puedan surgir bajo ciertas condiciones operacionales. Éstos y otros aspectos técnicos deberán considerarse junto a aquellos establecidos en el estándar IEEE 1547 para garantizar la confiabilidad del sistema eléctrico, así como la seguridad tanto del sistema como de sus

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empleados y sus clientes. Además, los acuerdos y procedimientos que se establezcan en el estándar de interconexión deberán incorporar las mejores prácticas contemporáneas de interconexión. Éstos deben incluir aquellas adoptadas en los métodos establecidos por las asociaciones de agencias estatales reguladoras. Entre éstos, se destaca el modelo de interconexión de la National Association of Regulatory Utility Commissioners, (NARUC), el cual incluye guías de los procesos de revisión técnica y administrativa y un modelo para el acuerdo de interconexión. De igual manera, al evaluar un estándar de interconexión es necesario considerar los costos asociados al proceso de interconexión. Entre éstos están relacionados a los trabajos necesarios para la interconexión segura de estos equipos. Actualmente, las prácticas de interconexión adoptadas por los Estados dispone que el cliente que solicita la interconexión es responsable de asumir ciertos costos asociados a la misma. Éstos típicamente incluyen los costos de los estudios de ingeniería, trabajos en el campo y reemplazo de equipo o construcción de instalaciones eléctricas por parte

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de la compañía de electricidad para viabilizar la interconexión. Generalmente las compañías informan a sus clientes el costo de realizar el trabajo y el cliente determina si desea continuar con el proceso de interconexión. Otro aspecto que considera la Autoridad, al evaluar establecer este estándar, es el impacto que el mismo puede ocasionar a su estabilidad financiera. Los clientes con generación propia suplirán parte de sus cargas eléctricas, por lo que comprarían menos energía a la Autoridad. A pesar de esto, la Autoridad tiene que mantener una capacidad adecuada en su sistema para suplir todas las cargas de los clientes con generación distribuida cuando éstos no generen. Por otra parte, la adopción de un estándar de interconexión ayudaría a fomentar el desarrollo de generación con fuentes de energía renovable. La disponibilidad de algunas de las fuentes de energía renovables, tales como el viento y el sol, es variable y depende de factores tales como las condiciones climáticas, las horas del día o la época del año. Al estar interconectados al sistema de la Autoridad, se reduce o elimina la necesidad de incorporar tecnologías de almacenamiento de

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energía, o sea, baterías, o generadores de resguardo, lo que reduce significativamente el costo de estos sistemas. Como resultado de la evaluación realizada, la Autoridad entiende que debe adoptar el estándar de interconexión para generación distribuida que cumpla con lo establecido en el Interconnection Standard for Distributed Resources del EPACT2005. El mismo debe considerar las particularidades del sistema eléctrico de la Autoridad y armonizar los procedimientos a sus procesos administrativos. Con esta información concluimos nuestra ponencia. Muchas gracias.

OFICIAL EXAMINADOR:

Muchas gracias al compañero Juan Alicea Flores, al licenciado Félix Pérez Rivera, la ingeniera Sonia Miranda. Ingeniero Alfredo Huertas, ¿usted tiene alguna pregunta para el panel o para el Deponente?

ASESOR TÉCNICO:

Tengo preguntas en relación a... En los sistemas que tiene actualmente la Autoridad para la medición, para ... [ininteligible] entiendo, por lo que ustedes explican, que no tiene la capacidad de memoria y que son inteligentes. La pregunta mía va

encaminada a que si alguien en particular quisiera conectarse, que sería posible con la tecnología actual conectarle a esa persona en particular un medidor inteligente, que sea capaz de tener la... almacenar la lectura para poderse acoger a la carga por tiempo?

ING. JUAN F. ALICEA FLORES:

Sí, aquí hay dos cosas. Para el primer... para el primer estándar, que es el... el de...

ASESOR TÉCNICO:

Sí, de medición.

ING. JUAN F. ALICEA FLORES:

El de medición, pues, obviamente, ahí pues no tendríamos el sistema actual de lectura remota, no tendríamos el sistema de metro. Sí, se puede incorporar un sistema de metro, pero tiene un costo que es bastante oneroso. Para el otro estándar, que aparentemente hubo una mezcla de su pregunta o una combinación en su pregunta, habría que instalar un sistema de medición un poquito diferente a lo que tenemos actualmente para poderlo hacer compatible... [ininteligible] de un sistema al nuestro.

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ASESOR TÉCNICO:

O sea, que no... ¿Con el sistema de comunicaciones actual no es compatible que se pueda poner un... uno en particular un, un... una persona en particular?

ING. JUAN F. ALICEA FLORES:

Como tal, en este momento no.

ASESOR TÉCNICO:

No. O sea, ¿tendría que cambiar, la Autoridad tendría que cambiar su sistema?

ING. JUAN F. ALICEA FLORES:

Tendría que cambiar el sistema de medición.

ASESOR TÉCNICO:

Por eso, entiendo que tienen que cambiar el sistema de la persona, pero no el de todos los demás, ¿o tendría que cambiar todo su sistema? Ésa es realmente la pregunta mía.

ING. JUAN F. ALICEA FLORES:

Bueno, entiendo que de la persona exclusivamente. El cliente facturado.

ING. SONIA MIRANDA:

Ingeniero Sonia Miranda para efectos de récord. Son varias las cosas que tiene que cambiar. Entendamos que no solamente el que el metro tenga

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capacidad de almacenar la información, sino que tener un sistema de comunicación para yo poder renovar y eso, pues, también tenemos que evaluar si tiene la capacidad hoy en día o no la tenemos. En caso de hoy día, yo puedo decir que es... [ininteligible], de ahí brincamos a la parte del sistema de almacenamiento de información ya ...[ininteligible]. Ahí hay que hacer modificaciones. También habría que hacer modificaciones al sistema de facturación y entonces ya no es únicamente el cambiar el medidor, sino todos lo asociado a esta tarifa.

ASESOR TÉCNICO:

Entiendo, porque yo entiendo que... Hay un refrán que dice muchos cabitos de vela hacen un sirio pascual. Si muchas personas dado el hecho del alza en precio del combustible decidieran, pues "mira, yo voy a hacer... [ininteligible] de 12:00 de la noche a 5:00 de la mañana, pues voy a lavar, voy a cocinar, voy a calentar agua", si se podría hacer factible en realidad, pues, paga menos y de esa manera puede... reduce la ...[ininteligible]. Sé que las diferencias son muy pocas, que el costo y la diferencia es poca, pero el costo de energía por

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kilovatio en la hora pico y a la hora... pero siempre puede haber alguien que quisiera... O sea, ¿habría la posibilidad?

INF. JUAN F. ALICEA FLORES:

Bueno, nosotros estamos dejando la puerta abierta para si en el futuro el patrón nuestro cambiase un poquito, podríamos reconsiderarlo. En estos momentos, dado a cómo se ha comportado otros países, dado a las pequeñas diferencias que existe entre lo que cuesta generar fuera de pico y en horas de pico y dado a la inversión que la Autoridad tendría que hacer, obviamente, el resultado neto sería que estaría, en estos momentos, posiblemente, crear un efecto de subirle en alguna porción, en vez de pequeña, al resto de los clientes.

OFICIAL EXAMINADOR:

A ver si entiendo. Porque la pregunta está dirigida, que hacemos, o sea, ...[ininteligible], cuando una persona dice: "yo quiero, yo absorbo el costo de poner el medidor, yo lo absorbo, yo lo pago, pero yo quiero... y yo voy a modificar mi comportamiento de consumo, yo lo voy a hacer". Lo que pasa es que según me indica la ingeniero Sonia,

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en su tercer punto ahí es que la Autoridad tiene unas limitaciones porque para poder atender a ese cliente, y esas dos premisas fundamentales que acaba de dar, pues la Autoridad tendría que hacer unos cambios sustanciales en lo que es su proceso de facturación que, en este momento, está limitada. En ese sentido, ¿entendí lo que... eso es lo que quiere decir?

ING. SONIA MIRANDA:

Es correcto.

OFICIAL EXAMINADOR:

Muchas gracias.

ASESOR TÉCNICO:

O sea, que cabe la posibilidad que si en un futuro, a medida que la tecnología va... ¿cómo se llama?, desarrollándose y si ustedes instalan un sistema de comunicaciones, pues a lo mejor en un futuro podría ser factible.

ING. SONIA MIRANDA:

Bueno, definitivamente la Autoridad no cierra las puertas a posibilidades y alternativas. Sin embargo, no es solamente los costos asociados al implementar este sistema, sino que si mira en el aspecto de lo que se ...[ininteligible] está el

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costo de producir esa energía. Al día de hoy no existe una diferencia sustancial que justifique que la persona haga un movimiento de conseguir, ¿verdad?, transferir ...[ininteligible] que tenemos en las horas pico a las no pico, con la diferencia tan poca que hay en el ...[ininteligible]. Y, por otro lado, la poca diferencia que hay entre la demanda de pico y la no pico, lo que podría causar es que saco...[ininteligible] no pico a una hora pico, verdad, fuera de pico, y le estaría causando un problema similar. O sea, que son muchas las variables que tengo que estar mirando. Sin embargo, uno no debe descartar porque uno busca un sistema eficiente que pudieran...[ininteligible].

ASESOR TÉCNICO:

Muchas gracias.

OFICIAL EXAMINADOR:

Muchas gracias. Le damos muchas gracias a los representantes de la Autoridad de Energía Eléctrica por su participación y entonces pasamos a llamar al doctor Agustín Irizarry Rivera.

DR. AGUSTÍN IRIZARRY RIVERA:

Muy buenos días.

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OFICIAL TÉCNICO:

¿Usted tiene copia de la ponencia suya?

DR. AGUSTÍN IRIZARRY RIVERA:

Sí, voy a sacar copia.

OFICIAL EXAMINADOR:

Adelante.

PONENCIA DEL DR. AGUSTÍN IRIZARRY RIVERA

DR. AGUSTÍN IRIZARRY RIVERA:

Buenos días. Este, quiero aclarar que esta ponencia ha sido redactada tanto por mí, Agustín Irizarry, como por el doctor Efraín O'Neill, que no se encuentra con nosotros por otros compromisos, pero la misma aparece firmada por ambos. En una Isla como Puerto Rico es importante que el Gobierno vele por el bien común, aquellas áreas de nuestra vida como sociedad, donde las condiciones económicas no necesariamente son la prioridad, sino el bienestar del pueblo. La confiabilidad de nuestro sistema eléctrico es parte del bien común, ya que el mismo es vital para nuestro desarrollo socioeconómico y no tenemos la posibilidad de interconexión con otros sistemas eléctricos, como sucede, por ejemplo, en los 48 estados contiguos de Estados Unidos. La protección del ambiente y el

velar por una justicia social y, en especial, en poblaciones vulnerables, es otro importante deber del Gobierno en su responsabilidad de velar por el bien común. En todo debate o discusión sobre nuestro futuro energético en el caso que nos toca hoy, el caso específico, debe hacerse énfasis y que las alternativas a evaluar no pueden ser vistas únicamente, o dando mayor peso, a las dimensiones económicas que a los aspectos ambientales y sociales relacionados a tales alternativas. Hacer lo contrario prepara el camino para controversias, problemas futuros y consecuencias no intencionadas que pudieron haber sido atendidos desde el inicio del proceso de evaluación, dando mayor participación en información a todos los sectores afectados positiva o negativamente. Durante el siglo XX la Autoridad de Fuentes Fluviales, y luego convertida en la Autoridad de Energía Eléctrica, tuvo la importante tarea de construir, mantener y manejar la infraestructura eléctrica que permitió el desarrollo económico de la Isla. Para esta tarea fue necesario el adquirir y combinar todos los recursos de energía eléctrica en Puerto Rico para lograr la costo-efectividad que permitía una

estructura jerárquica de operación de sistemas de potencia. En la última década del siglo XX los sistemas de potencia a nivel mundial experimentaron grandes cambios debido a adelantos tecnológicos, cambios en política pública y preocupaciones ambientales y sociales en distintos países. Las compañías eléctricas se reorganizaron de acuerdo a estos factores y a las realidades de cada país. Una constante en muchos países ha sido un énfasis en el servicio al cliente, por ejemplo, a través de programas vanguardistas de calidad de potencia, estrategias de reducción del uso de combustibles fósiles y un repensar en la estructura clásica de generación, transmisión y distribución a través de estrategias como generación distribuida y mayor participación de los clientes en el manejo de sus tarifas eléctricas. Nos ha llegado el momento en Puerto Rico de revisar la manera en que hemos manejado y estamos manejando nuestro sistema energético. Tenemos la oportunidad de iniciar esta evaluación de una manera que considere la totalidad y complejidad económica, ambiental y social del asunto. La Autoridad de Energía Eléctrica ha declarado su intención o inclinación a adoptar el

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Estándar de la Sección 1254, Interconnection Standards for Distributed Resources y a no adoptar el Estándar de la Sección 1252 Time-Based Metering and Communications. Ésta es la posición expresada en el documento "Consideración de los Estándares del EPACT 2005: Time-Based Metering and Communications Interconnection Standards for Distributed Resources", preparado por la División de Planificación y Estudios de la Autoridad de Energía Eléctrica, con fecha de junio de 2007.

OFICIAL EXAMINADOR:

Doctor, perdone que lo interrumpa. Creo que lo último que le oí decir es a los efectos solamente residenciales porque, según entendí, en aquellos de interés comercial ya, básicamente, la Autoridad cuenta con un estándar ...[ininteligible].

DR. AGUSTÍN IRIZARRY RIVERA:

Ésa es la posición de la Autoridad de Energía Eléctrica. A continuación expresamos nuestra opinión sobre cada una de estas intenciones. Con relación a la Sección 1254, Interconnection Standards for Distributed Resources. Aplaudimos la intención de la Autoridad de Energía Eléctrica a adoptar el estándar de la Sección 1254,

Interconnection Standards for Distributed Resources. Menciona la Autoridad de Energía Eléctrica en su informe que el reglamento que finalmente se adopte debe cumplir, y cito: "Con las normas, reglamentos y estándares aplicables, incluyendo el estándar IEEE 1547. Además, recomendamos que al diseñar los procedimientos y acuerdos de interconexión, la Autoridad considere los modelos establecidos en las guías de NARUC. No obstante, la Autoridad deberá armonizar los procedimientos establecidos en estas guías a sus procesos administrativos.", y cierro la cita. Es de suma importancia que al momento de producir el reglamento de interconexión, el mismo describa un proceso ágil y sencillo de interconexión a la red eléctrica que permita al pequeño productor comenzar a producir energía en un período corto. Que el mismo cumpla con los estándares aceptables de interconexión, sin inclusión de requisitos adicionales o especiales que encarezcan el sistema o su operación. En ese proceso es vital hacer una distinción entre generadores residenciales o comerciales de una capacidad pequeña, quizás menos de 50 kilovatios, y aquellos generadores de mayor

capacidad, aunque para efectos del sistema se consideren pequeños. La conexión de generadores residenciales debe fomentarse al máximo de manera que el pueblo tenga herramientas para asumir y manejar sus necesidades energéticas, en especial durante y después de eventos atmosféricos o problemas con el servicio eléctrico. Entendemos que la posible inversión económica en este proceso no debe recaer en su totalidad en la Autoridad de Energía Eléctrica; mas, sin embargo, la agencia debe convertirse en un ente facilitador de tales interconexiones a través de procesos administrativos y para obtención de permisos simples y en casos donde el impacto del sistema es prácticamente ninguno por ser generadores muy pequeños. El Gobierno, por otro lado, en su deber ministerial de velar por el bien común, debe establecer los incentivos económicos necesarios para que la ciudadanía tenga la posibilidad de adquirir e instalar estas tecnologías, como ha sucedido en otros países. Hacer lo contrario implicaría cargas adicionales al ciudadano promedio que impedirían su posibilidad de progreso social y cerrarías las puertas a alternativas ambientalmente

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mejores que la quema actual de combustibles fósiles. Solicitamos la oportunidad de participar en la creación de este reglamento de interconexión. Sugerimos la creación de una estructura colaborativa entre la Autoridad de Energía Eléctrica y la ciudadanía para producir ese reglamento y nos ponemos a la disposición del funcionario a cargo de esta tarea en la Autoridad de Energía Eléctrica para viabilizar esta colaboración. Nos interesa sobremanera la colaboración en la creación de este reglamento, en la definición de este proceso ágil y sencillo de interconexión a la red eléctrica, que permita al pequeño productor comenzar a producir energía en un período corto, pues es el primer paso o es el primer paso para que podamos en Puerto Rico iniciar una transición ordenada hacia recursos energéticos distintos a los combustibles fósiles. Con relación a la Sección 1252, Time-Based Metering and Communication. En lo que respecta a esta sección, la Autoridad de Energía Eléctrica se inclina por no adoptar ese estándar. Sin embargo, el análisis presentado en el documento de la Autoridad de Energía Eléctrica, y preparado por la División de

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Planificación y Estudios, para rechazar este estándar nos resulta un poco confuso y falto de los datos necesarios en el documento o disponibles a través de la Autoridad de Energía Eléctrica para estudiar las interioridades del análisis. Son múltiples las ventajas de ofrecer medición y facturación basadas en intervalos de tiempo de consumo y creemos que el asunto amerita mayor consideración y posible adaptación para los clientes residenciales. A continuación presentamos algunas de estas ventajas. En su informe titulado "Assessment of Demand Response and Advanced Metering", la Federal Energy Regulatory Commission (FERC) define el concepto de medición avanzada como: Medición avanzada es un sistema de medición que registra el consumo de clientes y, posiblemente, otros parámetros, cada hora o más frecuentemente, y que provee para transmitir este registro diariamente o más a un centro de recolección de datos usando una red de comunicaciones. El concepto fundamental en la definición de medición avanzada envuelve mucho más que un metro capaz de medir en intervalos frecuentes. La medición avanzada se refiere a la

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medición, red de comunicaciones y al sistema de recolección y procesamiento de datos. Esta infraestructura se conoce como la Infraestructura de Medición Avanzada. En nuestra opinión, el espíritu del mandato del EPACT2005 es, precisamente, hacia el desarrollo y utilización de este tipo de infraestructura de medición avanzada para proveer a los clientes mejores maneras de manejar su consumo eléctrico al poder responder a cambios en precios de la electricidad o a incentivos diseñados para reducir el consumo, como, por ejemplo, "demand side management". La medición avanzada apoya distintas estrategias; entre ellas, el uso de tarifas basadas en tiempo de uso, "time of use", TOU, por sus siglas en inglés, de una forma moderna y creativa. La medición avanzada permite muchas cosas como, por ejemplo, mejorar el servicio que ofrece la compañía de electricidad al cliente, reducir el robo de electricidad detectando intervenciones con el sistema, permite monitorear la calidad de la potencia servida al cliente, mejora el manejo de apagones, mejora el pronóstico de demanda y la gerencia de los equipos de la compañía, identificando con precisión la carga a

servir por una línea de distribución o un transformador específico. Este último punto permite que la compañía de electricidad escoja la capacidad de los equipos a utilizar en forma más eficiente y económica. El uso de medición avanzada permite el mejor manejo de asuntos de importancia para el pueblo de Puerto Rico y para la Autoridad de Energía Eléctrica, como lo son el manejo de la vegetación y el mejor monitoreo del nivel de voltaje en el punto de conexión del cliente. En el análisis presentado por la Autoridad de Energía Eléctrica no se considera ninguna de estas ventajas. Otra oportunidad que provee la medición avanzada es proveer información automatizada al cliente para que pueda manejar su consumo. Por ejemplo, existen en el mercado termostatos inteligentes. A éstos se les puede enviar señales de precio a estos controladores de temperatura inteligentes, termostatos inteligentes, que ajusten la temperatura de sistemas de aire acondicionado para clientes residenciales con aire central o a clientes comerciales e industriales. La comunicación ocurre... [ininteligible]. Nos confunde el análisis hecho por la Autoridad de

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Energía Eléctrica que el mismo sólo usa la curva de demanda agregada, la suma de la demanda de todos los clientes, para caracterizar todos los días del año, aunque sabemos que en sus operaciones la Autoridad de Energía Eléctrica usa una curva para domingo, otra para sábado, otra para el viernes, otra para el lunes y una quinta curva para martes, miércoles y jueves. Además, aunque la curva de demanda agregada utilizada fuera el promedio de las anteriores, la misma es muy pobre en su resolución de la demanda. A pesar de que no existe demanda agregada por debajo de unos 2,300 megavatios, la curva tiene el rango en el eje vertical comenzando en cero, impidiendo apreciar los detalles de los cambios de la demanda según pasa el tiempo. Otro asunto que nos causa confusión es el cómputo de una demanda base, cantidad a ser suplida por unidades bases o de menor costo, no de 2,300 megavatios, como muestra la curva de la demanda, sino de 3,074 megavatios, cantidad muy cercana a la demanda pico de alrededor de 3,600. También nos resulta confuso el llamado costo de generación para el 2009, entre siete y nueve centavos por kilovatio hora, que se presenta sin justificación alguna, excepto que es

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el resultado del uso de un programa de computadoras. ¿Por qué, si el costo de generación en el 2009 será de unos nueve centavos, hoy pagamos unos diecinueve centavos por kilovatio hora? Nos parece que las pérdidas en la transmisión y distribución, otros servicios y la compra de combustible no justifican esa diferencia. La realidad es que no podemos evaluar adecuadamente los cómputos hechos por la Autoridad de Energía Eléctrica, pues no tenemos acceso alguno a los datos usados para hacer los cómputos. Éste es, en nuestra opinión, la falla mayor de este proceso, el proceso de la creación del documento que usa la Autoridad de Energía Eléctrica para justificar su decisión y el proceso de esta vista pública, el que otras entidades o el público no participaron en el proceso. Y no es suficiente que haya un estudio de EPRI o de cualquier otra entidad externa a la realidad del país. En Puerto Rico contamos con los recursos para atender apropiadamente éste y otros asuntos energéticos y, en caso de que sea necesario recurrir a peritaje externo, existen recursos locales para evaluar los resultados de tales estudios. El EPACT2005 ordena a las compañías

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eléctricas y a las comisiones de servicio público, a ambas, a evaluar la interconexión, la medición avanzada y otras disposiciones. En varios documentos federales la Comisión de Servicio Público de Puerto Rico aparece ejerciendo una función reguladora en Puerto Rico del servicio eléctrico, aunque en conversaciones con funcionarios de la Comisión de Servicio Público nos indican que esto no es así. Ante la falta de un mecanismo como la Comisión, que en los Estados Unidos vela mayormente por los intereses del ciudadano promedio, es imperativo al evaluar la implantación de EPACT2005... perdón, es imperativo al evaluar la implantación de EPACT2005 que se identifiquen los mecanismos para lograr la justa representación de la ciudadanía en este proceso. Esto no implica que tengamos que esperar a que se legisle tal representación. Es nuestra esperanza que de esta vista surja una apertura en la Autoridad de Energía Eléctrica que viabilice este proceso participativo en asuntos que directamente afectan a los clientes. Los procesos políticos tomarán nota y se legislará luego lo que sea necesario. Podemos actuar ahora. Sugerimos que no

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se abandone la consideración de medición avanzada, por los beneficios de conservación y mejoras al servicio que recibe el cliente que esta medición puede traer. Recomendamos revaluar estas medidas, no sólo desde el punto de vista económico, sino también considerando los beneficios ambientales y sociales de esta tecnología. Comentarios finales. La historia de la humanidad está llena de ejemplos en donde países, personas u organizaciones han estado en momento cruciales de decisión que marcaron su destino. Lo triste en muchos casos es no darse cuenta en ese momento de la importancia de los mismos. Puerto Rico enfrenta un momento crucial en el desarrollo de sus recursos energéticos. Salieron del país en el año 2006 por encima de 6,000 millones de dólares para la compra de combustibles fósiles de acuerdo con el estudio hecho por el profesor Alameda, del RUM. En Puerto Rico, donde no tenemos ningún combustible fósil, debemos explorar todas las posibles alternativas y evaluarlas no sólo en términos de costo-efectividad, sino en términos ambientales y sociales. Es importante usar un marco de referencia mayor al ciclo político de cuatro años y

entender que el problema es mucho más complejo que meramente reducir el costo de la energía eléctrica a corto plazo. El Gobierno tiene la obligación de tomar decisiones, posturas y realizar inversiones aunque a corto plazo tenga un costo económico mayor que otras alternativas, pero que a largo plazo son mejores no sólo en términos económicos, sino también en términos ambientales y sociales. Recordemos que las decisiones de infraestructura que tomemos hoy estarán con nosotros por los próximos treinta o cuarenta años. Entendemos que la Autoridad de Energía Eléctrica vele por sus intereses y su salud financiera, al igual por cumplir su compromiso con los bonistas. De igual forma, entendemos y apoyamos el derecho que tiene todo cliente residencial, comercial e industrial de tener acceso a información sobre el servicio eléctrico que recibe, a cómo se usa los dineros que paga por el servicio y oportunidades para ahorrar en el servicio eléctrico a través de programas o tecnologías disponibles ahora o en un futuro cercano. La Autoridad de Energía Eléctrica y sus clientes no tienen por qué tener una relación adversarial, si queremos que Puerto Rico enfrente

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exitosamente los retos que imponen el presente estado mundial de los combustibles fósiles y nuestra dependencia de éstos. Para lograr mantener la confidencialidad necesaria de la información en la Autoridad de Energía Eléctrica, pero a la vez asegurar que los clientes tengan justa representación es, por tanto, necesario que en el desarrollo de los reglamentos relacionados a las disposiciones de EPACT2005 participe algún organismo cuyo primordial fin sea asegurar el mejor trato y las mejores oportunidades para los clientes, con el mínimo de obstáculos y barreras regulatorias y económicas. Ofrecemos como opción en este proceso participativo al Instituto Tropical de Energía, Ambiente y Sociedad, (ITEAS)del Recinto Universitario de Mayagüez. En ITEAS tenemos representadas sobre quince disciplinas, tenemos un compromiso con un futuro sostenible para Puerto Rico donde se trate la situación energética desde una perspectiva que integre la economía, ambiente y la sociedad. Solicitamos la oportunidad de participar en la consideración que la Autoridad de Energía Eléctrica tiene que hacer en o antes del 6 de agosto de 2008 sobre otras disposiciones del

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EPACT2005, pues la ciudadanía tiene mucho que ganar si las mismas se atienden apropiadamente. En especial es de suma importancia la participación ciudadana activa, no sólo a través de vistas públicas como ésta, en el análisis e implementación de la Sección 1251 de "metering", pues ésta afecta directa y positivamente a la ciudadanía. Una estructura colaborativa entre la Autoridad de Energía Eléctrica y la ciudadanía para considerar la medición neta, otras medidas pendientes, como la desarrollo de los reglamentos de ...[ininteligible], permitiría atender las preocupaciones sociales y ambientales, además de participar en la creación del reglamento. Sería un ejercicio muy saludable y mejor sintonizado con los tiempos que vivimos, tiempos donde los ciudadanos a nivel mundial tienen mayor participación de la que ofrecen, por ejemplo, estas vistas. Nuevamente nos ponemos a la disposición del funcionario a cargo de esta tarea en la Autoridad de Energía Eléctrica para viabilizar esta colaboración. Hacemos un llamado urgente al Director Ejecutivo de la Autoridad de Energía Eléctrica, a la Junta de Gobierno y su Presidente, para que se alcen en una

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gesta histórica de apertura de la Agencia al ciudadano promedio, a una nueva era donde la Autoridad de Energía Eléctrica facilite la transición de Puerto Rico hacia recursos y prácticas energéticamente sostenibles. En varias ocasiones hemos conversado tanto con el Director Ejecutivo como con el Presidente de la Junta de Gobierno y entendemos que existen los espacios y la disposición para lograr ese futuro sostenible para Puerto Rico. Esta apertura, en lugar de debilitar la Autoridad de Energía Eléctrica, tiene el potencial de mejorar sus relaciones con el Pueblo y cumplir de mejor manera con su misión y abrir nuevas oportunidades de crecimiento económico. Es fundamental establecer nexos entre la Autoridad de Energía Eléctrica, otras agencias de gobierno, la industria, el comercio y la ciudadanía a través de los cuales pasemos de una relación adversarial a una colaborativa, que pasemos de desconfianza a un compromiso serio y duradero por el bien común, por el bienestar social, ambiental y económico de Puerto Rico. Atentamente, Agustín Irizarry y Efraín O'Neill.

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OFICIAL EXAMINADOR:

Muchas gracias al doctor Agustín Irizarry. ¿Si el ingeniero Huertas tiene alguna pregunta que realizar? Con relación a la sugerencia finale, que usted propone una colaboración con la sociedad. Que usted sepa, ¿en los Estados Unidos hay algún precedente en esa línea que usted pueda citarnos específicamente?

DR. AGUSTÍN IRIZARRY RIVERA:

Normalmente en los Estados Unidos las compañías eléctricas son privadas y la Comisión de Servicio Público son los entes que dan paso a la intervención ciudadana a través del... [ininteligible]. Sin embargo, existen ejemplos de creaciones de institutos con el propósito de promover la política pública energética, donde entren la participación de la academia, la ciudadanía general, grupos de acción ciudadana, industrias, gobierno y las compañías de electricidad. En Hawaii, por ejemplo, que se parece mucho a nosotros, porque son islas, existe un instituto de política pública bajo el Departamento de Ciencias Sociales de la Universidad de Manoa, en Hawaii, donde se desarrolló una

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infraestructura colaborativa donde participan representantes de la industria eléctrica, de la industria de la transportación, gobierno, academias, industrias en general y la ciudadanía. Y su objetivo fue el desarrollo de un plan de diez puntos para poder ir hacia un desarrollo sostenible para el Estado de Hawaii. Eso tuvo serias consecuencias sobre el asunto de cómo se manejaba la infraestructura energética de Hawaii. Así que sí existen ejemplos de foros colaborativos creados con el objetivo de llegar a la mesa y conversar y negociar y entendernos, porque aún cuando esta vista, ésta que estamos viviendo, es muy cordial. Yo he estado en vistas que no lo son. La realidad, el asunto adversarial puede ocurrir en dos planos, puede ser uno adversarialmente muy cordial o adversarialmente muy efectivo. No permite, sin embargo, esta vista el intercambio que debería existir. Es como el metro actual de energía eléctrica, mide en una sola dirección. Solicitamos sentarnos a la mesa donde conversemos y podamos encontrar juntos eso. Eso es mucho más efectivo y ha resultado en estados más rápidos, en lugar donde por ejemplo, ...[ininteligible].

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OFICIAL EXAMINADOR:

No tenemos ninguna otra pregunta. Muchas gracias al doctor Agustín Irizarry. Siguiendo con la vista, tenemos al ingeniero Peter Sinz. Vamos a recesar cinco minutos, en lo que nos estiramos y entonces continuamos.

--FUERA DE RÉCORD--

OFICIAL EXAMINADOR:

Continuamos con los procedimientos hoy, 9 de julio de 2007. El Deponente el ingeniero Peter Sinz.

PONENCIA DEL INGENIERO PETER W. SINZ

ING. PETER W. SINZ:

Buenos días. Como expliqué, ésta es la ponencia desde el punto de un usuario de un sistema. Señores, en dicha consideración la Autoridad expresa su preocupación sobre, y cito, "Efectos de Interconectar Generadores con el Sistema de Distribución", que tenemos que pensar que están al alcance de resolver con los recursos con los cuales la Agencia debe disponer. No puede ser tan totalmente impráctico, antieconómico y hasta peligroso hacer estas interconexiones como se está haciendo a través del mundo entero, en lo que ya son millones de instalaciones sin los posibles

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problemas a los cuales aluden. Los controles y técnicas para evitar cualquier problema ya existen. Están en Alemania, España, California, Hawaii y en muchos sitios a la vista de todos. No es tan nuevo para que no existan soluciones a estas preocupaciones. La adopción de la tecnología existente es crucial para no atrasar más la oportunidad de progreso económico y estratégico de nuestros ciudadanos, comerciantes e industriales. Hay países y regiones que ya tienen metas y fechas específicas de producir desde veinte por ciento, veinticinco por ciento y hasta cien por ciento de su energía total con fuentes renovables, reduciendo su dependencia y contaminación en una forma seria y responsable. Se está perdiendo de vista que cada instalación generatriz típica consume combustible que, en realidad, ni sabemos su costo ni su efecto ecológico para el futuro. Además, es obvio que debemos liberarnos lo más posible de combustibles cuyo precio, calidad y disponibilidad están en manos de gobiernos y políticas mundiales abiertamente contrarias a nuestro sistema de vida. No hacerle frente activo y urgente a esta realidad se podría catalogar de una falta de resolución

consciente a estas realidades. En mi casa hay un sistema fotovoltaico en uso. Tengo lo que se llama "conocimiento de causa". Sería triste pensar que los autores de las consideraciones y preocupaciones expresadas en esta convocatoria a Vistas Públicas no puedan cualificarse en este aspecto ni tener a su alcance recursos al efecto. Me explico, de ver cómo funciona el sistema. Hay una realidad práctica que se tiene que considerar. Actualmente el costo de un sistema fotovoltaico es alrededor de unos doce dólares por vatio nominal instalado. Con ayudas económicas casi insignificantes disponibles, el incentivo del ciudadano, comerciante o industrial es de bajar su gasto económico en su consumo eléctrico por el alto costo en Puerto Rico, aún sin saber lo que va a pasar en el futuro. Ya hay un claro esfuerzo en conservación. Ahora se contempla producción. La interconexión, la disponibilidad de tarifas variables del tipo TOU (Time of Use y otros), sí son ayudas importantes, pero nunca serán la motivación de inversión con la oferta actual de la agencia de acreditar sólo el costo diferido del sobrante de producción que pudiera crearse. La preocupación expresa en esta

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convocatoria es que la interconexión de generadores al sistema de distribución puede tener un impacto económico a las compañías eléctricas, léase la Autoridad de Energía Eléctrica, es un casi invisible. Puedo demostrar por récords llevados en mi persona, con el sistema instalado en mi casa, de hecho, está disponible para verificación por sus técnicos, lo siguiente: La capacidad nominal de los quince paneles fotovoltaicos de 170 watts cada uno representan una capacidad nominal de 2,550 watts o unos 2.5 kilos. Nunca han producido más de 1,500 watts. Esto es aproximadamente sesenta por ciento de lo óptimo que se acerca al 75 por ciento que la industria estima es un promedio. La curva de producción es muy gradual, empezando y terminando en cero, con la producción de más de 1,000 watts, empezando a las 3 horas de amanecer hasta unas cuatro horas antes de atardecer, que en un día típico serían unas seis horas. Esto podría representar en teoría un máximo de 7.5 kilovatios hora por día, unos 225 kilovatios hora por mes, porque hay muy pocos momentos en el día promedio donde coincidiría un sobrante y sería muy suave su entrada y salida. Compara eso con el golpe que una

planta eléctrica suelta cuando se sale de secuencia de 10, 15 o 20 kilovatios. Aún presumiendo que dispongo de 25,000 dólares para gastar en sólo producir y desconectar mi sistema con, digamos, hasta diez kilovatios hora por día, 3,600 kilovatios por cada doce meses, necesitaríamos unas 70,000 instalaciones para equivaler el uno por ciento en la producción anual de la AEE, de unos 24.8 giga watts hour. Con un dos por ciento de límite la mayoría de las regiones controlan estas instalaciones para el futuro. California planea tener un millón de instalaciones para el 2010, con un cinco por ciento de participación. Ni el bolsillo ni el sistema de la AEE está en peligro por mucho tiempo. Sin embargo, si pensamos que cada barril de petróleo produce unos 550 kilovatios hora, los sistemas fotovoltaicos ayudarían a rebajar nuestra dependencia de los combustibles fósiles y rebajar nuestra producción de contaminación. Conclusión inescapable: Los sistemas fotovoltaicos y, de hecho, cualquier sistema de producción eléctrica renovable por medio renovable es positivo para la economía de Puerto Rico. Todo incentivo económico, con ejemplos de

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otras partes del mundo, son buenos y necesarios para Puerto Rico. Cuanto antes, mejor. Sometido. Perdonen los errorcitos de...

OFICIAL EXAMINADOR:

Muchas gracias al compañero Peter Sinz por su participación. Ingeniero Huertas, ¿tiene alguna pregunta para el Ingeniero?

ASESOR TÉCNICO:

Tengo un par de preguntas. ¿El sistema usted lo tiene actualmente funcionando en su casa?

ING. PETER W. SINZ:

Sí.

ASESOR TÉCNICO:

¿Y está interconectado con el de la Autoridad o está desconectado?

ING. PETER W. SINZ:

Lo instalé puramente por la curiosidad técnica que me ha caracterizado toda mi vida, pero también como un ejemplo de qué pasa, para averiguar cómo pasa. No está conectado a la Autoridad y mi esperanza era reducir un veinte por ciento de mi consumo, que estamos de los 1,800 a 1,900 kilovatios hora por mes se están economizando como 300; o sea, que estamos en un quince, dieciséis por ciento.

ASESOR TÉCNICO:

O sea, pero entonces, ¿cómo usted lo opera, se desconecta de la Autoridad y se conecta ahí manualmente??

ING. PETER W. SINZ:

No, no. Estos sistemas son, este... el corazón del sistema es el controlador que controla la energía de 24 voltios corriente directa en los mismos paneles, la transmite a la batería de 12 voltios que está conectada para convertirla en 24, y mientras haya energía de los paneles, el consumo sobre 300,000 voltios de la casa, dos veces lo dejé conectado a la Autoridad porque sé que es demasiado fuerte para que el sistema sea útil. Y el consumo de la casa si excede a lo que está produciendo los paneles, el controlador le saca energía a la batería. Perdóneme, si el consumo excede la producción, la batería, el controlador le roba al sistema potencia. Si la producción es en exceso a lo que estamos consumiendo, lo deposita en la batería. El único momento, por eso es que digo que estos sistemas no representan un riesgo económico ni típico para la Autoridad porque el único momento en que yo estaría depositando corriente en un

sistema interconectado sería cuando el exceso de mi producción a mi consumo ya cargó las baterías y, en ese momento utópico sobra un poquito de energía y no hace daño. Claro, entendemos que un sistema, por ejemplo, en una escuela o en mi casa, si yo me voy de vacaciones por un mes, pues tendría más oportunidad de producir corriente para darle a la Autoridad; pero aún así lo más que yo he visto que esté produciendo ese sistema es 1,100, 1,200, 1,300 watts, que no es una carga que va a desconcertar el sistema radial ni tumbar el voltaje al sistema de la Autoridad. O sea, que en esa parte no le veo una preocupación crítica a la Autoridad, acerca de estos diferentes productores que, a la vez, lo que va a pasar con mi producción cuando llega al "grill" de la Autoridad, entiendo que la Autoridad va a sobre vencerlo, que va a pasar que el vecino, el vecino estaría usando mi consumo. Lo mío va a llegar a Palo Seco a afectar... porque es como una corriente de agua en una tubería. O sea, lo que yo pongo se encuentra con una producción de miles de kilovatios hora y sencillamente caerá en el vecino o algo así. No regresa.

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ASESOR TÉCNICO:

Para entender su explicación, o sea, ¿que usted tiene parte de su sistema 110 conectado continuamente al sistema fotovoltaico y el resto del sistema continuamente al de la Autoridad?

ING. PETER W. SINZ:

Exacto. Yo separé las del... creé un panel nuevo.

ASESOR TÉCNICO:

¿No hace transferencia ni nada?

ING. PETER W. SINZ:

Sí. Creé un panel nuevo para poner el 110 que recibe de los paneles o de las baterías.

ASESOR TÉCNICO:

¿Y ahí es que usted hace la transferencia?

ING. PETER W. SINZ:

Y la transferencia es automática con el controlador. Sin embargo, el controlador también tiene, porque son muy sofisticados, tiene la capacidad de si sobrara alguna corriente, mandarle en un "green time" a la Autoridad. Tiene la capacidad de ordenar a una planta eléctrica que entre al sistema si hay una pérdida total. O sea, que el controlador es en sí una computadora pequeña que supervisa todo.

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ASESOR TÉCNICO:

Pero vuelvo a la pregunta. Lo que pasa es que si él entra es que tiene que entrar en su propio...

ING. PETER W. SINZ:

No, no, por eso yo lo... La planta de Palo Seco cuando empezó en el '59...

ASESOR TÉCNICO:

Por eso, o sea, que están separados.

ING. PETER W. SINZ:

Sí, sí, están separados.

ASESOR TÉCNICO:

Porque uno de los problemas que tiene la Autoridad, obviamente, es los sistemas de generación, que habría que tener el sistema de sincronización si están fuera o si está continuamente sincronizado, que es otro tipo de arreglo. Y, obviamente, la capacidad depende...[ininteligible] en el sentido de que no debe...

ING. PETER W. SINZ:

Estos paneles, control, que se usan en Estados Unidos en todos lados, tienen esa capacidad de estar sincronizados continuamente con la red; o sea, que la corriente que tiene se transfiere directamente cuando están conectados. Cuando no

están conectados no hay nada que hacer. Si no... entiendo que no hay baterías en mis paneles, y cuando se acabe eso el sistema sí podría recibir de la Autoridad corriente por el 110; no enviar, recibir.

ASESOR TÉCNICO:

Y si el metro... entiendo entonces que el metro puede... si empieza desde de la base hacia arriba.

ING. PETER W. SINZ:

De hecho, yo, yo... El sistema mío no puede mandarle corriente a la Autoridad, no está preparado para eso. Es un "stand-alone system", no es un "grid-tie system".

ASESOR TÉCNICO:

Okay. Ahora, ahora creo que...

ING. PETER W. SINZ:

Bueno, lo que quiero es economizar par de cien pesos al mes. Digo, quizás...

ASESOR TÉCNICO:

Que le pague la inversión.

ING. PETER W. SINZ:

Pero es que para mi pensar nosotros estamos en una competencia mundial en temas políticos y energéticos y si no hacemos algo, nos van a comer

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vivos. Estos ...[ininteligible] no son buena gente, son malos y nos quieren comer.

ASESOR TÉCNICO:

Ingeniero, como cuestión de derecho, sobre lo que se ha discutido no solamente en el informe sino en la vista, en la posición de la Autoridad, ellos se inclinan a adoptar, eh...

ING. PETER W. SINZ:

La interconexión.

ASESOR TÉCNICO:

...la interconexión si es que, en su momento, se reglamentara el acuerdo a los límites 1547 y las guías de NARUC. ¿Estamos claros en eso?

ING. PETER W. SINZ:

Estamos clarísimos. Y los sistemas que existen ahora por Xantrex son diferentes manufactureros Ford, Chevrolet, Buick, lo que sea, toman en cuenta todas las necesidades y son automáticas y son completamente "reliable"; o sea, no han habido casos de cortocircuitos para los sistemas ni nada y estamos nosotros...[ininteligible] imagínese, en España y en Alemania son industrias de cientos. En España ...[ininteligible] de 36,000 personas empleados instalando sistemas eléctricos, que no

van a tener 25 por ciento de toda su energía para el año 2010, toda su energía será instalada por el viento. Bridges Colombia declaró que para el año 2025 no va a usar ningún combustible fósil, cero. En los estados, en Estados Unidos, donde hay una relación no tan cercana entre el gobierno y las generatrices, que hay un generador privado y una... [ininteligible], New Hampshire prometió que... hay como tres estados que han dicho para que el año 2020 tienen que tener veinte por ciento de su producto; para el año 2020 usted me tiene que producir veinte por ciento de su venta de electricidad por medios renovables. Y para el 2025 tiene que tener veinticinco por ciento y si no, es "out of business". O sea, pero la preocupación mía es que en presencia de estas posibilidades, seguimos bajo la espada de Damocles, que si... ¿qué pasaría en Puerto Rico si el petroleo sigue a 250 pesos el barril? Si no tenemos algún método alterno de la nevera correr o qué sé yo. Tenemos que ir pensando en todo esto, además de conservación, que la Autoridad está haciendo un esfuerzo grandísimo y está dando un incentivo si la factura se paga por internet, cosas así, todo eso

es creación inteligente y brillante. Pero yo no veo que Puerto Rico tenga una producción sólida si no tiene, por ejemplo, cuarenta, treinta, cincuenta por ciento de su energía y nadie se la puede quitar. Sólo el viento y las mareas del mar. Hay muchas formas de hacerlo, pero si Puerto Rico no tiene esa "fall-back", estamos en manos de esta gente, que es lo que está pasando. Si China y India siguen consumiendo petróleo, el precio va a seguir subiendo y eso está fuera de nuestro control. Estamos viendo que está pasando. Globalmente estamos en aguas turbias.

OFICIAL EXAMINADOR:

Muchas gracias al Ingeniero por su participación. Dado que no hay ningún otro deponente...

ING. PETER W. SINZ:

Como les dije, si la gente... como les dije, si la gente de la Autoridad quieren ir a casa, y sentar un técnico allí veinticuatro horas para que vean cómo funciona y la forma en que entra y sale, la fuerza que tiene y no tiene, está a su disposición cien por ciento.

OFICIAL EXAMINADOR:

Muchas gracias, muy amable. Dado que no hay

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deponentes adicionales, nosotros vamos a dar por terminados los trabajos durante el día de hoy. Son las 11:30 de la mañana.

ING. SONIA MIRANDA:

Sonia miranda para propósitos de récord. El anuncio que salió público indica que vamos a estar disponibles hasta las 2:00 de la tarde. Por consiguiente, tenemos que esperar hasta esa hora por si aparece alguien más.

OFICIAL EXAMINADOR:

Siendo eso así, pues vamos a tomar un receso y estaremos aquí hasta las 2:00 esperando a cualquier otra persona que aparezca. Muchas gracias.

--FUERA DE RÉCORD--

OFICIAL EXAMINADOR:

Muy buenas tardes. Les habla el ingeniero y licenciado Edison Avilés Deliz, para propósitos de récord soy el Examinador de estas Vista. Son las 2:00 de la tarde de hoy, 9 de julio de 2007. Dado que no llegaron más deponentes, vamos a dar por terminados los trabajos de la tarde de hoy. Muchas gracias a todos por su asistencia.

FINALIZAN LOS PROCEDIMIENTOS A LAS 2:00 P.M.

C00088

CERTIFICACIÓN DE TAQUÍGRAFA DE RÉCORD

Yo, Maribel Rivera Sánchez, taquígrafa de récord, certifico:

Que la que antecede es una transcripción fiel y exacta del testimonio prestado y el procedimiento llevado a cabo ante mí en la Vista Pública sobre los Estándares del EPAct2005 - Time Based Metering and Communications e Interconnection Standards for Distributed Resources, la cual se llevó a cabo en Ponce, Puerto Rico, el día 9 de julio de 2007.

Que en esta misma fecha estoy remitiendo el original y dos copias de dicha transcripción a la ingeniero Sonia Miranda Vega a su dirección en la Autoridad de Energía Eléctrica en Santurce, Puerto Rico.

Y para que así conste, firmo la presente en Toa Alta de Puerto Rico, a 13 de julio de 2007.

Maribel Rivera Sánchez

TAQUÍGRAFA DE RÉCORD

G00089

000090

Apéndice B

C00091

ORIGINAL

EN EL ESTADO LIBRE ASOCIADO DE PUERTO RICO
AUTORIDAD DE ENERGÍA ELÉCTRICA DE PUERTO RICO
SAN JUAN, PUERTO RICO

TRANSCRIPCIÓN DE VISTA PÚBLICA SOBRE:

LOS ESTÁNDARES DEL EPAct 2005
TIME-BASED METERING AND COMMUNICATIONS E INTERCONNECTION STANDARDS FOR DISTRIBUTED RESOURCES
SECCIONES 1252 Y 1254

LUGAR:	AUTORIDAD DE ENERGÍA ELÉCTRICA EDIF. JUAN RUIZ VÉLEZ SALÓN DE CONFERENCIAS SANTURCE, PUERTO
OFICIAL EXAMINADOR:	ING. Y LCDO. EDISON AVILÉS DELIZ
FECHA:	10 DE JULIO DE 2007
HORA CITADA:	10:00 AM
HORA COMIENZO:	10:00 AM
HORA FINALIZA:	2:00 PM

>>

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Í N D I C E

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COMPARECENCIA

ING. Y LCDO. EDISON AVILÉS DELIZ

OFICIAL EXAMINADOR

ING. ALFREDO HUERTAS DEL TORO

ASESOR TÉCNICO

ING. JUAN F. ALICEA FLORES

LCDO. FÉLIX E. PÉREZ RIVERA

ING. SONIA MIRANDA VEGA

POR LA AUTORIDAD DE ENERGÍA ELÉCTRICA (AEE)

SR. ALAN RIVERA RUIZ

POR LA ASOCIACIÓN PUERTORRIQUEÑA PARA LA ENERGÍA VERDE (APEV)

ING. GERARDO COSME NÚÑEZ

POR SOLARTEK

ING. WALTER PEDREIRA

DR. ALBITH COLÓN

POR ACONER-PR

ING. FERNANDO ABRUÑA
POR: US GREEN BUILDING COUNCIL - CAPÍTULO DEL CARIBE, AMERICAN INSTITUTE OF ARCHITECTS - CAPÍTULO DE P.R., COLEGIO DE ARQUITECTOS Y ARQUITECTOS PAISAJISTAS DE P.R.

ING. JORGE EL KOURY
POR EL COMITÉ DE ENERGÍA DE LA CÁMARA DE COMERCIO

SR. JOHN MILLER
POR LA ALIANZA DE ORGANIZACIONES COMUNITARIAS Y AMBIENTALES EN ACCIÓN SOLIDARIA (ACAAS)

ING. JUAN A. PÉREZ GONZÁLEZ
ING. ENRIQUE SIACA
ING. PETER SINZ
POR EL COLEGIO DE INGENIEROS Y AGRIMENSORES DE P.R.

SR. HÉCTOR ARANA
EN SU CAPACIDAD PERSONAL

SRA. MARIBEL RIVERA SÁNCHEZ
TAQUÍGRAFA DE RÉCORD

000095

INTRODUCCIÓN

OFICIAL EXAMINADOR:

Muy buenos días a todos los presentes. Hoy es 10 de julio del 2007. Les habla el ingeniero y licenciado Edison Avilés Deliz, nombrado por la Autoridad de Energía Eléctrica para ser el Oficial Examinador de estas vistas. Me acompaña el ingeniero Alfredo Huertas, quien es mi Asesor en cualquier aspecto técnico, ya sea durante la vista o en el proceso de redacción de mi informe después de celebrada la vista. Cumpliendo con el debido proceso de ley en estos procedimientos, estas vistas fueron debidamente notificadas en dos distintos periódicos de circulación general, según consta en las afidávit 76,749 y 65,725, 65,726 y 65,727. La afidávit 76,749 es del periódico El Vocero. Está suscrita por Marisol Ramos Miranda y lee: "Yo, Marisol Ramos Miranda, habiendo prestado el juramento debido, declaro lo siguiente: que soy Supervisora de Cuentas a Cobrar del periódico El Vocero de Puerto Rico, el cual se publica en San Juan, Puerto Rico y que en las ediciones de este mismo diario correspondiente a los siguientes días 22 y 23 de junio del 2007 se dio publicidad al

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aviso expedido por Autoridad de Energía Eléctrica sobre el asunto mencionado y copia del cual se une al presente afidávit para que forme parte del mismo. San Juan, Puerto Rico, 6 de julio del 2007." Así también, las afidávits 65,725, 26 y 27 son del periódico El Nuevo Día y están suscritas por Lissette Cortés y lee: "Yo, Lissette Cortés, habiendo prestado el debido juramento declaro: que soy Coordinadora de Diagramación y Ventas del Periódico El Nuevo Día que se publica en Guaynabo, Puerto Rico. Que en las ediciones de este Periódico correspondientes a los días 23 de junio, 22 de junio y 21 de junio se dio publicidad al edicto expedido por el ingeniero Jorge A. Rodríguez, Director Ejecutivo, en el caso arriba mencionado, copia del cual se une al presente afidávit para que forme parte del mismo." Para cuestión de récord aclaramos que el afidávit 65,725 corresponde al 21 de junio del 2007. La 65,726 corresponde al 22 de junio del 2007. Y la 65,727 corresponde al 23 de junio del 2007. Así también, dichas notificaciones se publicaron en la hoja cibernética de la Autoridad de Energía Eléctrica. Todas las anteriores afidávits se hacen formar

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parte del expediente administrativo. Estas vistas se celebrarán para cumplir con lo dispuesto en el Energy Policy Act 2005 el cual le requiere a la Autoridad de Energía Eléctrica la celebración de Vistas Públicas con la finalidad de determinar si se adoptan o no los siguientes estándares: Time-Based Metering and Communications, Interconnection Standards for Distributed Resources, que son básicamente las secciones 1252 y 1254 de la Ley PURPA. Como previamente notificado, estaremos aceptando ponencias escritas durante la mañana de hoy hasta las 2:00 de la tarde. Las personas a deponer durante el día de hoy les recuerdo, que según previamente establecido, el tiempo para exponer es de quince minutos, con la salvedad que como Oficial Examinador y dependiendo de las circunstancias particulares de cada vista, me reservo la potestad de extender dicho tiempo a petición de parte. Les recuerdo que deben tener los teléfonos celulares en el modo silencioso. En el caso de tener que atender dicho teléfono para cualquier asunto, lo harán fuera del salón. Finalmente les aclaro que estas vistas son para que reaccionen al informe Consideración de los

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Estándares del EPACT 2005: Time-Based Metering and Communications Interconnection Standards for Distributed Resources, preparado por la División de Planificación y estudios de la Autoridad de Energía Eléctrica con fecha de junio del 2007. Y como norte, los propósitos de la Ley PURPA, que con promover la conservación de la energía y promover las que proveen las compañías de electricidad, optimizar la eficiencia en el uso de instalaciones y recursos de las compañías de electricidad y establecer tarifas equitativas para los consumidores de electricidad. Siendo eso así, ya tengo una lista, hasta el momento tenemos ocho deponentes. Vamos a iniciar con el ingeniero Juan F. Alicea de la Autoridad de Energía Eléctrica. Buenos días, Ingeniero.

PONENCIA DE LA AUTORIDAD DE ENERGÍA ELÉCTRICA

LCDO. FÉLIX E. PÉREZ RIVERA:

Muy buenos días al Oficial Examinador, a su Asesor; buenos días a todos los visitantes. Comparecemos en la mañana de hoy por la Autoridad de Energía Eléctrica. Como muy bien señaló el Honorable Oficial Examinador, el ingeniero Juan F. Alicea Flores, quien es Director de Planificación y

Protección Ambiental en la Autoridad de Energía Eléctrica, comparecemos también en la mañana de hoy la ingeniero Sonia Miranda, Jefa de División Planificación y Estudio de la Autoridad y el licenciado Félix E. Pérez Rivera de Asuntos Jurídicos de dicha entidad. Como deponente en la mañana de hoy va a estar el ingeniero Alicea Flores en representación del Director Ejecutivo de la Autoridad de Energía Eléctrica, el ingeniero Jorge Rodríguez. También comparecen o estamos presente en esta sala funcionarios que confeccionaros el informe o la ponencia que va a presentar ante su consideración el ingeniero Alicea Flores. Sin más preámbulos, pues, dejamos a nuestro deponente, representante de la Autoridad de Energía Eléctrica en la mañana de hoy a estas vistas públicas.

ING. JUAN F. ALICEA FLORES:

Muchas gracias, Licenciado, y muy buenos días a todos aquí.

OFICIAL EXAMINADOR:

Buenos días.

ING. JUAN F. ALICEA FLORES:

Muy especial al distinguido Oficial Examinador y a su Asesor Técnico. Mi nombre es Juan F. Alicea.

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Soy Ingeniero, Director de Planificación y Protección Ambiental y comparezco a estas vistas públicas en representación del ingeniero Jorge A. Rodríguez Ruiz, Director Ejecutivo de la Autoridad de Energía Eléctrica. Comparecemos para presentar la posición de la Autoridad con relación a dos de los estándares establecidos en el Energy Policy Act del 2005, el cual enmendó la ley federal Public Utility Regulatory Policies Act, mejor conocida como PURPA. Estos estándares son el Time-Based Metering and Communications e Interconnection Standard for Distributed Resources. Es relevante expresar que nuestra ponencia está fundamentada en el Informe "Consideraciones de los Estándares del EPACT 2005: Time-Based Metering and Communications y el Interconnection Standards for Distributed Resources", que estuvo disponible a todo el público en las oficinas comerciales que fueron informadas en el aviso de estas vistas públicas que publicamos en varios periódicos de circulación general de Puerto Rico. Así también, está disponible en una dirección de Internet que informamos en dicho aviso. La Autoridad debe determinar si implanta los estándares en Puerto Rico para lograr los

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propósitos de PURPA. Éstos son: promover la conservación de la energía que proveen las compañías de electricidad, optimizar la eficiencia en el uso de instalaciones y recursos de las compañías de electricidad y establecer tarifas equitativas para los consumidores de electricidad. La Autoridad tomará su determinación respecto a la adopción de estos estándares, conforme a la información que se presente en estas vistas y las recomendaciones del Oficial Examinador. En primer lugar, explicaremos el estándar Time-Based Metering and Communications. El propósito de este estándar es proveer a todas las clases de clientes y a clientes individuales, según soliciten, tarifas cuyos cargos varíen durante los diferentes períodos de tiempo y reflejen la diferencia, si alguna, en los costos que incurre la compañía de electricidad en generar y comprar energía. El EPACT05 menciona ejemplos de cuatro tipos de tarifas, éstas son: Tiempo de Uso o TOU, el Critical Peak Pricing, CPP, o Real Time Pricing, RTP, y créditos para clientes con carga. Las tarifas en las cuales los precios varían dependiendo del precio en que el cliente usa la energía tienen como propósito proveer señales de

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precios para que éstos decidan cuándo consumir la electricidad. Esto podría resultar en reducciones en la demanda en horas en las cuales producir la energía es más cara, es más costosa y, de esta manera, también aumenta la confiabilidad del sistema. Además, esto podría reducir la necesidad de añadir al sistema de generación unidades que se utilizan en períodos de demanda alta, tales como las turbinas de gas. Según PURPA, las tarifas basadas en tiempo deben ser costo efectivas, esto significa que los beneficios que recibe a largo plazo tanto la compañía de electricidad como los clientes exceden los costos asociados con la implementación de estas tarifas. Esto hace necesario que al considerar adoptar este estándar se evalúen los costos que tendría que incurrir la compañía de electricidad. Algunos de éstos son: inversión en medidores y otras infraestructuras para recopilar datos, costos administrativos, adiestramiento técnico a los empleados para analizar la información y cambios en programación para facturar a los clientes. Los costos relacionados con el procesamiento de datos pueden aumentar debido al volumen de información. También,

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se deben considerar los costos administrativos para implementar y promocionar la tarifa basada en tiempo y educar a los clientes. Los medidores tradicionales no tienen la capacidad requerida para que las compañías de electricidad implementen tarifas basadas en tiempo. Los medidores inteligentes pueden registrar y almacenar el consumo de energía de clientes por períodos de tiempo. Con esta información se puede facturar a clientes con tarifas basadas en tiempo. Por lo tanto, la compañía de electricidad tendría que incurrir en costos para la adquisición e instalación de medidores nuevos. Estos costos dependen de la tecnología del metro, de la cantidad de medidores a adquirir y del tipo de tarifa basada en el tiempo que se adopte. La Autoridad está en el proceso de completar la instalación de medidores de lectura remota por medio de TWACS (Two Way Automatic Communication System) para todos los servidores... todos los servicios a distribución secundaria. Los medidores de TWACS no poseen memoria para almacenar la información del consumo y demanda por período de tiempo. Por lo tanto, la Autoridad no tiene medidores capaces de agrupar el

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consumo del cliente por período de tiempo para los servicios a voltaje de distribución secundaria. Sin embargo, existen en el mercado medidores con esta capacidad, pero son más costosos que los medidores utilizados actualmente. Cabe señalar que en la mayoría de las ocasiones los clientes deben alterar su patrón de consumo para beneficiarse de las tarifas basadas en tiempo. La acogida de estas tarifas depende grandemente de qué los ahorros que obtiene el cliente excedan los costos e inconvenientes en que tienen que incurrir para cambiar su patrón de consumo. La Autoridad tiene disponible tarifas a tiempo de uso para las clases de servicio comercial e industrial en su estructura tarifaria. Esto debido a que los clientes comerciales e industriales tienen más oportunidad de transferir parte de su carga y modificar su patrón de consumo. En nuestro análisis graficamos la curva de demanda para definir cuáles son los periodos de tiempo pico y fuera de pico de nuestro sistema actual. Las gráficas están posteadas aquí a nuestra derecha y se pueden ver diferentes tres tipos de gráficas. La gráfica de demanda total del sistema, que una de ellas, muestra que no hay

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variaciones significativas en la demanda en períodos de 24 horas. Además, analizamos qué porción de la generación se suple con unidades base y de unidades pico. De este análisis surge que la demanda de lunes a viernes, entre 12:00 de la medianoche y 9:00 de la mañana se suple con unidades base, por lo que este período se puede clasificar fuera de pico. El resto del tiempo en los días de semana es período pico, el cual se suple con unidades base y unidades pico. Los fines de semana se pueden clasificar como períodos fuera de pico, con excepción de las 7:00 de la noche a las 12:00 de la medianoche. También, estudiamos el comportamiento de la clase residencial y cómo éste afecta la curva de demanda del sistema. En el análisis determinamos que la demanda máxima de los clientes residenciales ocurre dentro del período pico del sistema de la Autoridad, o sea, aproximadamente entre 7:00 de la noche y 12:00 de la medianoche. Al igual que la curva del sistema, en los fines de semana se observa un aumento de demanda desde las 7:00 de la noche hasta las 12:00 de la medianoche. Utilizamos modelos matemáticos para calcular el precio promedio de la generación

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total para los períodos pico y fuera de pico del año 2009. Los resultados del análisis indican que la diferencia en costo entre los períodos es mucho menor de 1 centavo; o sea, fluctúa entre .15 y .47 centavos por kilovatio hora. La razón principal que propicia que esta diferencia no sea significativa es la mejora en la eficiencia de las unidades pico, lo cual reduce los costos de producción. Algunas de éstas son: la conversión de la Central Cambalache a Ciclo Combinado, el aumento en capacidad y eficiencias de las turbinas de gas de Mayagüez, la adición al sistema del Ciclo Combinado de San Juan y el uso de gas natural en la Central Ciclo Combinado de Aguirre. Como resultado de esta evaluación la Autoridad entiende que no debe adoptar el estándar Time-Based Metering and Communication para la clase residencial. La razón principal para que la Autoridad no adopte ese estándar para los clientes residenciales es que, de acuerdo con el comportamiento típico de la clase residencial y a la corta duración del período fuera de pico, entendemos que a los clientes residenciales les resultaría poco práctico y difícil transferir la carga. Si el cliente no

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puede transferir la carga, la tarifa podría resultarle más costosa que una tarifa basada en costo promedio. Además, la demanda del sistema no tiene fluctuaciones considerables con respecto a la demanda máxima durante el período de 24 horas en cualquier día del año. Por lo tanto, el transferir cargas podría causar un pico de demandas en el período fuera de pico. Otra razón para no adoptar este estándar es que la diferencia en costos de generación entre los períodos pico y fuera de pico no justifican la transferencia de demanda de un período al otro. Además, la necesidad de remplazar el equipo de medición actual y modificar el sistema de facturación resultaría en un aumento en costos que revierte al cliente. Varias compañías en los Estados Unidos también recomendaron no adoptar ese estándar para la clase residencial. Estudios indican que algunas compañías tienen disponibles tarifas basadas en tiempo para clientes residenciales, pero éstas no tienen mucha acogida. La Autoridad continuamente realiza estudios para evaluar posibles tarifarias y podría considerar la viabilidad de este tipo de tarifa para los clientes residenciales en el futuro. Pasando al otro

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estándar, PURPA Sección 1254-Interconnection Standards for Distributed Resources. El segundo estándar que discutiremos es el de interconexión del EPACT05. El mismo establece que la compañía de electricidad deberá ofrecer servicios de interconexión a generadores localizados en los predios de los clientes al sistema de distribución eléctrica. Éste indica que estos servicios estarán basados en el estándar IEEE 1547 del Institute of Electrical and Electronics Engineers. Además, los acuerdos y procedimientos que se establecerán deberán incorporar las mejores prácticas actuales de interconexión, incluyendo las prácticas adoptadas por los modelos de interconexión de las asociaciones de agencias reguladoras estatales. Estos deberán ser justos y razonables y no discriminatorios o preferenciales. Durante la última década el tema de interconexión de generadores al sistema de distribución cobró fuerza en las compañías de electricidad a nivel nacional. Esto se debe, en parte, al desarrollo de las tecnologías de generación y protección utilizadas. Además, el desarrollo de estándares de interconexión por parte de varios estados pioneros,

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así como la redacción de modelos de interconexión por parte de entidades reguladoras, contribuyeron al crecimiento de los estándares de interconexión en los Estados Unidos. Recientemente el EPACT05, con su estándar de interconexión, aumentó la exposición del tema de interconexión a nivel nacional al requerir a las compañías de electricidad considerar la adopción del mismo. Entre los estados pioneros en el tema de interconexión está California, New York y Texas. Éstos tuvieron como meta desarrollar estándares de interconexión que estableciera una metodología uniforme para permitir la interconexión de sistemas de generación de manera segura y confiable. A pesar de que estos Estados realizaron procesos independientes para establecer sus estándares de interconexión, los resultados de los mismos fueron similares. De igual manera, entidades nacionales reguladoras desarrollaron modelos de interconexión que incorporan algunas de las prácticas incluidas en los estándares ya establecidos. A mayo del 2007, aproximadamente veinticuatro de los Estados han incorporado algún tipo de estándar de interconexión, según el Interstate Renewable Energy

Council. Estos estándares, por lo general, consideran los aspectos técnicos, administrativos y legales aplicables a la interconexión. La Autoridad, al considerar la implementación de un estándar de interconexión, debe evaluar los requisitos técnicos, administrativos y legales. Los requisitos técnicos aseguran que la interconexión de los generadores no afectará adversamente la confiabilidad del sistema eléctrico, así como la seguridad tanto del sistema como de sus empleados y sus clientes. Los requisitos administrativos definen los procedimientos y trabajos necesarios para lograr la interconexión. Los requisitos legales establecen los términos contractuales del acuerdo de interconexión. Como parte de la evaluación, la Autoridad examina los efectos de interconectar generadores a su sistema de distribución eléctrica. La configuración del sistema de distribución de la Autoridad es radial. Éste no está diseñado para incorporar fuentes de generación o almacenamiento de energía eléctrica externos. Por esto, la interconexión de generadores al sistema de distribución puede causar algunos problemas de seguridad, confiabilidad y de

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operación en el sistema. Entre éstos se encuentra la formación de islas eléctricas, efectos adversos al sistema de protección, sobrevoltajes, fluctuaciones de voltajes, inyección de corrientes harmónicas, parpadeos y resonancia. Todo estándar de interconexión tiene que tomar en cuenta los efectos adversos de interconectar generación para garantizar la seguridad y confiabilidad del sistema eléctrico. El EPACT 2005 establece que los estándares de interconexión que adopten las compañías eléctricas deben estar basado en el estándar IEEE 1547. Éste provee una metodología uniforme para la interconexión de generadores al establecer los requisitos técnicos mínimos para lograr la interconexión segura y confiable al sistema de distribución eléctrica. El mismo señala cómo los generadores operarán bajo condiciones normales y ante disturbios en el sistema de distribución. Además, incluye los requisitos y especificaciones de pruebas a los que se someterán estos equipos. El estándar no incluye todos los aspectos técnicos que deben evaluarse para su cumplimiento. Por ejemplo, el estándar no establece límites de contribución de corrientes de

corto circuito que garantice que estos sistemas no afecten adversamente el funcionamiento de los equipos de protección. Tampoco considera la configuración de los transformadores de interconexión utilizados o los efectos de resonancia que puedan surgir bajo ciertas condiciones operacionales. Éstos y otros aspectos técnicos deberán considerarse junto a aquellos establecidos en el estándar IEEE 1547 para garantizar la confiabilidad del sistema eléctrico, así como la seguridad tanto del sistema como de sus empleados y sus clientes. Además, los acuerdos y procedimientos que se establezcan en el estándar de interconexión deberán incorporar las mejores prácticas contemporáneas de interconexión. Éstos deben incluir aquellas adoptadas en los modelos establecidos por las asociaciones de agencias estatales reguladoras. Entre éstos, se destaca el modelo de la interconexión de la National Association of Regulatory Utility Commissioners, NARUC, el cual incluye guías de los procesos de revisión técnica y administrativo y un modelo para el acuerdo de interconexión. De igual manera, al evaluar un estándar de interconexión es necesario

considerar los costos asociados al proceso de interconexión. Estos costos están relacionados a los trabajos necesarios para lograr la interconexión segura de estos equipos. Actualmente, las prácticas de interconexión adoptadas por los Estados dispone que el cliente que solicita la interconexión es responsable de asumir ciertos costos asociados a la misma. Éstos típicamente incluyen los costos de los estudios de ingeniería, trabajos en el campo y reemplazo de equipo o construcción de instalaciones eléctricas por parte de la compañía de electricidad para viabilizar la interconexión. Generalmente, las compañías informan a sus clientes el costo de realizar el trabajo y el cliente determina si desea continuar con el proceso de interconexión. Otro aspecto que considera la Autoridad, al evaluar establecer este estándar, es el impacto que el mismo puede ocasionar a su estabilidad financiera. Los clientes con generación propia suplirán parte de su carga eléctrica, por lo que comprarían menos energía a la Autoridad. A pesar de esto, la Autoridad tiene que mantener una capacidad adecuada en su sistema para suplir todas las cargas de los

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clientes con generación distribuida cuando éstos no generen. Por otra parte, la adopción de un estándar de interconexión ayudaría a fomentar el desarrollo con fuentes de energía renovable. La disponibilidad de algunas fuentes de energía renovables, tales como el viento y el sol, es variable y depende de factores tales como las condiciones climáticas, la hora del día o la época del año. Al estar interconectados al sistema de la Autoridad, se reduce o elimina la necesidad de incorporar tecnologías de almacenamiento de energía o generadores de resguardo, lo que reduce significativamente el costo de estos sistemas. Como resultado de la evaluación realizada, la Autoridad entiende que debe adoptar el estándar de interconexión para generación distribuida que cumpla con lo establecido en el Interconnection Standard for Distributed Resources del EPACT05. El mismo debe considerar las particularidades del sistema eléctrico de la Autoridad y armonizar los procedimientos a sus procesos administrativos. Con esta información concluimos nuestra ponencia. Muchas gracias a todos.

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OFICIAL EXAMINADOR:

Muchas gracias al ingeniero Alicea, al licenciado Rivera y a Sonia Miranda, la ingeniero Sonia Miranda. Ingeniero Alfredo Huertas, ¿tiene alguna pregunta?

ASESOR TÉCNICO:

No por al momento.

OFICIAL EXAMINADOR:

Este Examinador tampoco tiene preguntas para la Autoridad de Energía Eléctrica; así que, puede retirarse.

ING. JUAN F. ALICEA FLORES:

Permiso para retirarnos.

LCDO. FÉLIX PÉREZ RIVERA:

Muchas gracias. Buen día.

OFICIAL EXAMINADOR:

Básicamente, como Oficial Examinador voy a seguir un listado que me dieron que básicamente creo que se basa en orden de llegada. Sin embargo, voy a hacer un aparte y voy a permitirle al señor Alan Rivera de APEV que tome el siguiente turno dado su condición física.

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PONENCIA DEL SR. ALAN RIVERA RUIZ

SR. ALAN RIVERA RUIZ:

Buenos días.

OFICIAL EXAMINADOR:

Muy buenos días.

SR. ALAN RIVERA RUIZ:

Mi nombre es Alan M. Rivera Ruiz. Si me permite la mesa antes de comenzar, hay una *fe de errata* en el documento y si me lo permite, quisiera hacer énfasis en algunos de ellos importantes. Página tres: en los "bullets" segundo, donde dice la sección 3, en vez de "poder", potencia eléctrica. El "bullet" sección 5, en vez de "poder", energía eléctrica. Página cinco: segundo párrafo, donde dice "células" es celdas de combustible. Segundo párrafo página siete: debe leer 300 kilo watts hora, kwh; 10 mega watts hora, mwh.

OFICIAL EXAMINADOR:

Perdón. ¿Me puede repetir eso?

SR. ALAN RIVERA RUIZ:

Cómo no. Segundo párrafo en gris en donde dice "300 kv", debe leer kwh y donde dice "10 mw" debe leer 10 mwh. Página ocho: párrafo en gris final se resta, se quita "uso de poder" se tacha y se coloca

G00117

la palabra demanda. Página once punto cuatro: en vez de kv, kw. Página trece último párrafo: "dan base a la apreciación de" y debe leer después de "de" la AEE de.

OFICIAL EXAMINADOR:

Repite eso, por favor. ¿Que dan base a?

SR. ALAN RIVERA RUIZ:

Que dan base a la apreciación de la AEE de que el "time based metering". Página catorce segundo gris en el medio a la derecha: "este modelo" se tacha. Ah, y muy importante en la página veinte Alan en la firma. Cuando me permitan.

OFICIAL EXAMINADOR:

Adelante.

SR. ALAN RIVERA RUIZ:

Gracias. Muy buenos días estimado Director Ejecutivo, Autoridad de Energía Eléctrica, Oficial Examinador de Vista, Consultor Jurídico de la Autoridad de Energía Eléctrica del Estado Libre Asociado de Puerto, distinguidos deponentes, ciudadanos todos. El asunto Consideración de los Estándares del EPACT 2005: Time-Based Metering and Communications Interconnection Standards for Distributed Resources. Expongo como ciudadano,

G00118

consumidor residencial y usuario del sistema de la Autoridad de Energía Eléctrica, así como miembro asociado y fundador de la Asociación Puertorriqueña para la Energía Verde, Incorporado. La Asociación Puertorriqueña de Energía Verde, APEV por sus siglas, es una iniciativa comunitaria sin fronteras entre los municipios de Puerto Rico con la misión de que en nuestro país todo aquel individuo que quiera generar por sus propios medios electricidad derivada de fuentes de energía renovable, entiéndase aire, agua, sol, termal y biomasa, sepa que tiene el derecho a hacerlo con la misión personal de no seguir siendo vapuleados por los altos costos que el estado nos impone por su adicción al combustible fósil y la misión comunitaria de contribuir a un ambiente mucho más saludable para nosotros y para los que nos hereden. El Energy Policy Act 2005 fue firmado el 8 de agosto de 2005. Este enmendó la Public Regulatory Policies Act, PURPA, Título XXII, Electricidad, Subtítulo E, Sección 111(d) para requerir a las compañías de electricidad consideren adoptar nuevos estándares. Provisiones del acta de política de energía del 2005. Las provisiones adicionales en

EPACT afectan el desarrollo de la generación distribuida que de ahora en adelante en este documento se referirá por sus siglas en inglés DG, y la consideración de ello por consumidores y planificadores de sistemas eléctricos y operadores. Por ejemplo, la Sección 1211 de EPACT pide el desarrollo de una Organización de Confiabilidad Eléctrica, ERO, y la implementación del mandato con estándares de confiabilidad eléctrica ejecutables. La Sección 1221 de EPACT pide que el DOE o el Departamento de Energía estudie la congestión de transmisión y posiblemente designar áreas obligadas de interés nacional como corredores de transmisión eléctricos. El subtítulo de EPACT E contiene enmiendas al PURPA. La Sección 1251 de EPACT pide la adopción de estándares para la medición neta; éstas pueden afectar la interconexión del sistema DG con la red eléctrica. La Sección 1252 de EPACT contiene estándares para la medición inteligente y fijación de precios en base al tiempo que son generalmente pensados como mecanismos de implementación importantes para la consideración de inversiones en DG por compañía de energía eléctrica y consumidores. Hago una pausa aquí porque nos

preocupa como Asociación de que las pasadas citadas no estén dentro de la vista pública actual y quisiéramos que como parte del informe que salga de esta vista pública hubiese algún tipo de explicación si ha habido alguna vista pública que nosotros no conocemos que se haya dado sobre el tema de la medición neta o sobre cualquiera de los otros secciones o subtítulos del EPACT porque entendemos que la Autoridad conoce de nuestro interés en el tema del pasado año y no hemos tenido ningún tipo de comunicación ni citado para ninguna vista pública en donde se atiendan esos puntos.

OFICIAL EXAMINADOR:

Gracias por darme la oportunidad. Con relación a ese punto que trae el Deponente le recordamos que esta vista es para evaluar la viabilidad de la adopción por parte de la Autoridad de Energía Eléctrica del 1252 y el 1254. Los otros, que son parte de la enmienda, serán considerados en su momento en otra vista pública por la Autoridad de Energía Eléctrica.

SR. ALAN RIVERA RUIZ:

Excelente. Gracias por la información. Paso a la página tres. Las áreas específicas de ventajas

000121

potenciales cubiertas en el estudio "The potential benefits of distributed generation and rate-related issues that may impede their expansion a study pursuant to section 1817 of the Energy Policy Act 2005", febrero 2007 fue la entrega, al Departamento de Energía de Estados Unidos es un informe que es parte del EPACT y del cual hacemos entrega copia como Anejo B al documento de ponencia. Aquí lo tenemos disponible para la mesa. Este documento es el estudio que pidió el Departamento de Energía sobre todos y cada una de las secciones del EPACT 2005. Requerimos que los hallazgos formulados en el estudio del DOE federal sean incluidos como parte de los hallazgos en el informe de esta Vista Pública. La APEV proveerá copia, como en estos momentos hemos hecho, como parte de esta ponencia en los documentos de anejo. En la presentación entregada por la Autoridad de Energía Eléctrica establece que la Autoridad debe establecer si la implantación de cada estándar en Puerto Rico es apropiada para lograr los propósitos de PURPA. La determinación debe realizarse por escrito, tomando en cuenta los hallazgos y las evidencias que se presenten en vista pública. La Autoridad de Energía

000122

Eléctrica es una corporación pública propiedad del pueblo de Puerto Rico y sus acreedores y bonistas son a final de cuentas cubiertos con garantías dadas en base a un patrimonio nacional. Es a nos, el pueblo a quien se tiene que escuchar y servir con propósito óptimo y de futuro. Nuestra exigencia es que se incluyan los hallazgos y evidencias que presentamos a favor del aumento en cuota de energía alterna y la apertura a la generación distribuida. Paso a la página cinco abajo. En el 1993 el Gobierno de Puerto Rico formula varias iniciativas para crear una política pública en el tema de la energía. Primeramente, se crea la Administración de Asuntos de Energía transfiriéndose la OE a la misma bajo la sombrilla del Departamento de Recursos Naturales. En los '90 se toman varias acciones específicas y sustancialmente importantes para la economía energética de Puerto Rico. En diciembre del '93 el Comité de Cogeneración y Generación de Energía del Gobierno de Puerto Rico entrega un informe con recomendaciones sobre política pública energética de Puerto Rico. Es importante señalar que como parte de este Comité se encontraban como miembros y

firmantes de este documento directores de dependencia como la Junta de Planificación, la AAA, la Autoridad de Energía Eléctrica, la Junta de Calidad Ambiental, Compañía de Fomento Industrial, Departamento de Recursos Naturales y representantes del Departamento de Energía Federal. Este Comité propuso entre sus estrategias a corto, que serán cinco años; mediano, doce años y largo plazo lo siguiente. Proveer incentivos económicos para usuarios de energía eléctrica residencial y comercial para la compra de equipos y enseres con una alta clasificación de eficiencia energética. Proveer ayuda económica para proyectos pilotos dirigidos a la utilización de fuentes renovables de energía. Evaluar las fuentes y/o mecanismos mediante los cuales la generación de electricidad y venta de la misma se realice en la manera más costo-efectiva posible, incorporando los costos económicos, sociales, de salud pública y ambientales. Comenzar a generar energía utilizando como materia prima los desperdicios sólidos no tóxicos. Modificación de los códigos de construcción para permitir la incorporación de nuevas tecnologías, diseños eficientes y de

conservación de energía. Establecer normas de eficiencia energética para nuestras industrias como condición de permisos de operación y exención contributiva. La reconstrucción del Comité Asesor de Energía bajo la Ley 128 y la investigación científica en asuntos energéticos de Puerto Rico. Hoy, en el año 2007, estamos en el año catorce de este informe y la APEV exige se incluya en el informe final de estas vistas públicas qué seguimientos, estudios y previsiones se le han dado a tan importante e histórica pieza de política pública que intercede y converge con el tema que nosotros estamos tratando en la mañana de hoy. Históricamente representa un reto que la Autoridad en Puerto Rico mantenga el precio de la electricidad lo más bajo posible. Se haga una inversión recurrente en tecnología en armonía con principios ambientales locales e internacionales y se readiestre a todo recurso humano con una verdadera base de provecho, que establezca una economía energética científica y de aprovechamiento óptimo de nuestros recursos. Estamos en espera de la firma del poder Ejecutivo del Gobierno de Puerto Rico del proyecto de Ley 1212 para establecer una

forma de venta de electricidad generada por fuentes renovables parecida al "net metering" que acaba de aprobar el Legislativo. El mismo establecería la necesidad de que la Autoridad muestre las tablas tarifarias que aplicarían a esta modalidad de clientes generador residencial en el renglón de los 300 y comercial en el renglón de los 10 mega watt hora. Y que la Administración de Asuntos de Energía de Puerto Rico establezca los modelos de generadores a ser aprobados. La toma de decisión de la Autoridad sobre cambios tarifarios queda condicionada a nuestra aceptación de los mecanismos operacionales y de contratos aplicables, así como la firma de esta Ley. Hay varios motivos económicos e institucionales para los que las compañías de utilidades eléctricas no hayan instalado e invertido mucho en DG o en DG. Por ejemplo, la base económico del DG es una diferente de caso a caso. Es muy específica, es individual y por área. Por consiguiente, muchas de las ventajas potenciales son más fácilmente capturadas por los clientes generadores que aquellas por generación distribuida del lado de la utilidad. Esto ha conducido a la situación actual donde los modelos

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de inversión comercial para que utilidades eléctricas inviertan en DG no hayan surgido con tanto entusiasmo. Hago referencia al Anejo A que incluyo en esta ponencia. Este Anejo A se lo ofrecemos como referencia. Es un estudio que se hizo después de establecido el "net metering" en Estados Unidos. Este estudio lo dirigió en la Universidad de Vermont el grupo que trabaja las leyes ambientales y de energía y un grupo tan disciplinario y tiene una serie de recomendaciones muy interesantes, muy específicas de territorio y de estado, pero que muchas de ellas nos pueden ayudar a comprender una mejor manera de ver el "net metering" como alternativo. La Ley 145 aprobada en 2006 autoriza bajo la ley de Municipios Autónomos a la creación de corporaciones especiales de DG en cumplimiento a PURPA. Además, varias regiones han empleado programas de respuesta de demanda DR donde los incentivos financieros y/o tarifas son promocionados a clientes generadores para reducir su consumo de electricidad durante periodos pico. Clientes generadores que participan en estos programas usan DG para mantener sus operaciones cerca de lo normal mientras ello reduce su demanda

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en horas pico. Para esto es necesario que se estipule una nueva categoría de cliente en la Autoridad. El cliente generador en niveles residencial, comercial y/e industrial. Página diez. La APEV plantea que a menos que la Autoridad tenga para nuestro estudio y comentario resultados de proyectos pilotos en Puerto Rico en generación distribuida a nivel residencial, comercial e industrial, ya que no existen a nivel municipal, la Ley 145 de empresas especiales es nueva, que demuestre la necesidad de medidas restrictivas o mayores a la de otros estados y/o territorios de la nación se utilicen los estándares de la IEEE. Así también es preocupante que en esta vista la autoridad reguladora estatal, la Administración de Energía de Puerto Rico, no presente su posición o la misma no se haya hecho pública como parte de la presentación de la Autoridad de Energía Eléctrica. El dilema de costo versus beneficio. El resultado de esta carencia de integración de la generación distribuida en el sistema eléctrico de Puerto Rico es la de que muchos de los beneficios directos y prácticamente todos los indirectos del sistema DG no son capturados dentro de la contabilidad

tradicional del flujo de caja o "cash flow" en la Autoridad. Esto es principalmente el producto de una estructura reguladora histórica que ha producido inversión de capital específica y prioridades operacionales así como la tarea significativa de cuidar la red de generación central, línea de energía, subestaciones, así como satisfacer las necesidades del consumidor de la energía eléctrica. Desde sus inicios las comisiones reguladoras de utilidades públicas estatales han seriamente perseguido lo mejor posible, la combinación de servicios confiables y costos razonables bajos. Esta relación con las corporaciones de utilidades algunas veces como colegas, otras como argumentadores ha evolucionado en una serie de reglas generalmente aceptadas y prácticas comerciales en cuanto al método apropiado para estimar las propiedades de una tecnología, la utilización, la seguridad y el valor público. Los sistemas DG ya que han sido principalmente soluciones basadas en el consumidor, generalmente se han desarrollado fuera del marco regulador tradicional. Como nota importante la APEV pone en duda la efectividad e imparcialidad con la que se

escoge para la mesa de directores de la Autoridad de Energía Eléctrica aquellos que son representantes del interés público. La experiencia en los pasados dos años ha sido la de tener representantes que desconocen los procesos de reforma que los grupos de interés comunitarios, científicos y académicos estamos llevando en el país. No guardan relación alguna con los movimientos en defensa de nuestro patrimonio generatriz y han sido sumamente laxos y condescendientes en su rol como representantes. Sobre la medición de tarifas en base de tiempo, página trece. Entendemos la evaluación de datos históricos que dan base a la apreciación de que el "time-based metering" no es necesario adoptarlo. La APEV basa su evaluación en datos diferentes.

OFICIAL EXAMINADOR:

Permiso. Ahí usted corrigió, dijo que dan base a la apreciación de la AEE de que.

SR. ALAN RIVERA RUIZ:

Muchas gracias. Que dan base a la apreciación de la Autoridad de Energía Eléctrica de que el "time based metering" no es necesario adoptarlo. La APEV basa su evaluación en datos diferentes. Sobre todo,

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en la evaluación de costos futuros de combustibles fósiles. La Autoridad sólo proyectó cambios en costos hasta el 2009, cuando ésta es una decisión que, como ya se dijo en el informe política pública energética de 1993, debe medirse a corto, mediano y largo plazo en veinte años de duración total. En un escenario a veinte años la Autoridad no puede pretender que se continúe en el modelo actual sin tomar en consideración escenarios y variables que como corporación ya ha cuantificado, cualificado, previsto y llegado a conclusiones de política pública. No sería falta de visión. Sería ceguera. Fluctuaciones y trastornos internacionales, falta de capacidad local para manejar estos trastornos, política energética desagregada y dispersa en varios organismos gubernamentales y hasta en el sector privado, ausencia de planificación estratégica que integre todos los sectores de la economía y aquellas que integren la salud y bienestar de nuestra sociedad son factores que si no se toman en consideración, llevan a la Autoridad a reaccionar y no a evolucionar. La APEV recomienda que se trabaje una política de "time based metering" considerando propiciar un ambiente

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económico para que crezca dentro de la red una nueva clase de cliente, el generador DG sea residencia, comercial, industrial y municipal. En base a la Ley 145, la Ley, esperamos, 1212, u otras medidas de cartera económica como son los REC's, los certificados de...

OFICIAL EXAMINADOR:

Perdoneme que le diga. Como usted sabe, las ponencias tienen un tiempo de quince minutos.

SR. ALAN RIVERA RUIZ:

Usted me dice.

OFICIAL EXAMINADOR:

Básicamente le hemos... ya llevamos como veintitrés. Vamos a darle cinco minutos adicionales en consideración a las demás personas que están aquí.

SR. ALAN RIVERA RUIZ:

Gracias, agradecido. En base a la Ley 145, Ley 1212, u otras medidas de cartera económica como son los REC's y ventas de electricidad verde se propicia una inversión que brinda estabilidad responsable al ciudadano y a la corporación. La Autoridad tiene que brindar incentivos de tarifa, apoyo técnico y venta de productos y servicios. Su

000132

inversión contribuirá al bienestar ciudadano y del ambiente, así como seguridad total del sistema y el país. Requerimos se haga una vista pública específicamente para discutir el modelo que la Autoridad está dispuesto a auspiciar en términos tarifarios y de interconexión dando espacio que la corporación estudie los modelos sugeridos y pondere un modelo administrativo puertorriqueño. Para terminar, en la última parte de esta ponencia la APEV señala y quiere motivar a uno de los factores más importantes para que ocurra un cambio de actitud en la Autoridad, sus trabajadores. Ustedes que son los técnicos, administradores, gerenciales y obreros de nuestro patrimonio nacional energético tienen ante sí una misión patriótica y heroica ante su pueblo. Pero no es sacrificio lo que exigimos, es visión. Los momentos de bonanza y logros sindicales les han dado a casa uno de ustedes la oportunidad de crecer como una de las clases trabajadoras más educadas y de mayor responsabilidad del país. Sus organismos representativos han crecido al igual que la corporación midiendo y evaluando la bonanza histórica que la Autoridad le ha brindado a este

G00133

pueblo cual accionistas y bonistas sus uniones se deben a ustedes. Llegó la hora de la planificación para ser mejores, eficientes y duraderos para nos, el cliente, nos la ciudadanía. La APEV entiende que muchos de los proyectos pilotos que se deben llevar a cabo pueden ser auspiciados, fundados y asociados con ustedes y sus representativos sindicales. Es hora de que todos invirtamos en un nuevo modelo energético para el país y ser socios de nuestro futuro. Estos son algunos de los ejes principales de la ponencia. La ponemos a su disposición y estamos disponible para cualquier pregunta.

OFICIAL EXAMINADOR:

Muchas gracias al señor Alan Rivera por su ponencia. Ingeniero Alfredo Huertas, ¿tiene alguna pregunta? Yo tampoco tengo preguntas; así que, puede retirarse. Muchas gracias por su ponencia.

SR. ALAN RIVERA RUIZ:

Muchas gracias.

PONENCIA DEL ING. GERARDO COSME NÚÑEZ

OFICIAL EXAMINADOR:

Siguiendo el orden, vamos a llamar al ingeniero Gerardo Cosme, Solartek.

ING. GERARDO COSME NÚÑEZ:

Buenos días a los presentes.

OFICIAL EXAMINADOR:

Buenos días.

ING. GERARDO COSME NÚÑEZ:

Quiero hacer una pequeña corrección en mi ponencia también, es que no puse los números de página, para que... por si acaso, si hay esa directriz, pues, no se pierda el orden. Mi ponencia originalmente fue escrita en inglés debido a que ésta es una ley federal y por ser una ley federal, pues, obviamente, la consecuencia se... la respuesta de esta vista va para allá y es bueno que el récord esté congruente con el idioma que esté escrito la ley originalmente. Permítame un segundito. Comoquiera que sea, la voy a leer en español, así que...

OFICIAL EXAMINADOR:

Si quiere, la puede leer en inglés.

SR. GERARDO COSME NÚÑEZ:

No, es mejor en español. Escribirlo es una cosa, hablarlo es otra.

OFICIAL EXAMINADOR:

En caso de interpretación entonces, cuando estemos

000135

evaluando la documentación le damos la prioridad a la ponencia escrita en inglés.

ING. GERARDO COSME NÚÑEZ:

Sí.

OFICIAL EXAMINADOR:

Adelante, por favor.

ING. GERARDO COSME NÚÑEZ:

Okay. Mi nombre es Gerardo Cosme Núñez. Soy Ingeniero Profesional licenciado, miembro activo del Colegio de Ingenieros y Agrimensores y de la Cámara de Comercio de la cual soy pasado Presidente del Comité de Energía, y miembro además del Instituto de Ingenieros Electrónicos y Electricistas, lo que se conoce como la IEEE. Comparezco a este foro como ciudadano, Ingeniero y dueño de una empresa que por cerca de quince años ha estado laborando en el área de energética. Es entonces que como cliente de la Autoridad de Energía Eléctrica, Ingeniero, empresario y ciudadano consciente que desea lo mejor para la prosperidad económica de Puerto Rico y beneficios ambientales a nivel global, hago el requerimiento de la Autoridad de Energía Eléctrica que adopte las secciones de la ley de energía EPACT 2005, la de

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"net metering" 1251, "smart metering" 1252 e interconexión 1254.

OFICIAL EXAMINADOR:

Aprovechando nuevamente. Yo quiero aclarar que el ámbito de acción de estas vistas y el informe que nosotros vamos a redactar es 1252 y 1254. Ustedes vienen preparados, pueden exponer sobre la 1251 y sobre la 1253 si así lo desean, recordándole que también tiene una limitación de tiempo. En cualquier momento yo puedo tomar la determinación de basarme en el informe escrito y detener la exposición oral. Pero volvemos, en su momento se celebrarán otras vistas para evaluar y llegar a unas determinaciones sobre la 1251 y la 1253. Sin embargo, hoy, ayer y hoy es 1252 y 1254.

ING. GERARDO COSME NÚÑEZ:

La vista de hoy julio 10 del 2007 es dedicada a la sección 1252 y 1254 solamente. Asumo yo que esto es porque queda menos de treinta días para que la Autoridad de Energía Eléctrica tenga que responder a FERC. Es por tanto, que mis comentarios esta vez van a estar limitados a estas dos secciones. No tanto, requiero que la Autoridad de Energía Eléctrica, que trabaje en preparar las vistas

concernientes a la sección 1251 llamada "net metering" con un tiempo más razonable porque estas secciones de la EPACT 2005 son de mucha complejidad técnica y es crucial la participación de terceros que puedan ser individuos y organizaciones con peritaje en el tema para entonces implementar unos programas exitosos tanto de "net metering", "smart metering" y estándar de interconexión para el beneficio tanto de la Autoridad de Energía Eléctrica como sus usuarios como el público en general o el país en general. Para finalizar mi introducción, quiero comparar esta vista con un reflejo de cómo Puerto Rico está rezagado con el resto del mundo en respecto a incentivo, a fuentes renovables y eficiencia energética. Primero, esta vista se celebra en menos de treinta días para la fecha que la Autoridad de Energía Eléctrica tiene que responder a FERC. Segundo, el documento preparado por la Autoridad de Energía Eléctrica que presenta su posición a sus clientes a este tema es de pobre calidad con errores tipográficos, inclusive. Esto crea una impresión que los vastos recursos de la Autoridad de Energía Eléctrica no han sido empleados a su potencial esperado,

haciendo pensar a mí, y quizás a usted, que el análisis técnico y económico presentado en ese documento es igualmente cuestionable. Tercero, esta vista no debe ser programada por la Autoridad de Energía Eléctrica. Esta vista debe ser programada por la agencia reguladora de energía de nuestro territorio, la cual no existe porque estamos desprovistos de tener una agencia regulatoria energética. La Autoridad de Energía Eléctrica por inacción del gobierno por muchas décadas es nuestra compañía eléctrica y la agencia reguladora gubernamental en el área energética a la misma vez. La Autoridad de Energía Eléctrica además establece en su documento que contrataron a EPRI para conducir un estudio de los "issues" de la EPACT 2005. Como contribuyente entonces, requiero que la agencia gubernamental que maneja los "issues" del EPACT 2005, o sea, la Autoridad de Energía Eléctrica haga público este estudio. Trasfondo histórico local. El acta de PURPA del '78 requiere que las compañías eléctricas compren a los cogeneradores y pequeños generadores que su producción energética, a lo que ellos llaman el costo evitado. En 1983 la Autoridad de Energía

Eléctrica en respuesta a PURPA publicó un reglamento titulado "Rates and conditions of service for co-generators and small electric power producers". En este documento regulatorio se establece el proceso de cómo cumplir con los requerimientos de PURPA. Este reglamento fue derogado al final de los años '90. Desde esa fecha al presente PREPA todavía tiene que cumplir con PURPA, por lo que tiene que evaluar cada caso de forma individual por no tener un proceso estructurado para estos propósitos. Hoy en día en Puerto Rico cualquier cliente residencial, comercial o industrial que interese conectar su equipo de generación a la red eléctrica amparado en PURPA no sabe qué oficina de la Autoridad de Energía Eléctrica visitar, qué proceso debe seguir, qué aplicación debe llenar y todos los empleados en la Autoridad de Energía Eléctrica que uno pueda encontrar no saben nada al respecto al preguntársele sobre este tema. Entonces, ¿qué tenemos por estándares hoy en resumen? Veintinueve años después de PURPA un documento viejo de la Autoridad de Energía Eléctrica que puede ser usado como una guía, pero no existe una guía formal o

000140

estándares el presente. Por otra parte, tenemos el estándar de interconexión distribuida de la IEEE pendiente a ser adoptado en este agosto del 2007. También existe por otro lado el estándar de la UL 1741, que es un estándar más bien hecho para los manufacturadores, los fabricantes de estos equipos Básicamente, pues, al día de hoy no tenemos... estamos desprovistos de cómo pueden interconectar de una forma, este... entre el cliente y la Autoridad de Energía Eléctrica. Comentarios ya específicos a la sección 1254, interconexión. El propósito de adoptar el estándar 1547 de la IEEE, según el EPACT 2005, es para uniformar los aspectos técnicos de interconexión entre estados y compañías eléctricas. Aunque éste no es el caso de Puerto Rico, el cual es un sistema aislado, basado en una sola compañía eléctrica y, este... la Autoridad de Energía Eléctrica debe adoptar este estándar como el propuesto por la EPACT 2005. Este estándar establece criterios y requerimientos para la interconexión de recursos distribuidos con sistemas eléctricos. Propone requerimientos relevantes en la ejecución, operación, prueba y consideración de seguimiento y mantenimiento a estos sistemas. La

G00141

Autoridad de Energía Eléctrica entiendo que tiene en su discreción para usar otras guías como las publicadas por la National Society of Regulatory Utility Commissioners, como indicaron en su documento, para establecer los procesos administrativos de interconexión con sus clientes. Aquí se me acabó la tinta y el tiempo. Pasaré entonces a los comentarios de la sección 1252, "smart metering". La Autoridad de Energía Eléctrica lo menciona como el "time based metering and communication", pero realmente la sección completa se conoce como "smart metering", la sección 1252. El documento de PREPA establece que ellos tienen unas tarifas TOU por sus clientes industriales y comerciales, pero si uno ve el documento mismo de ellos publicado, tarifa para el servicio de electricidad, uno puede cuestionarse y esas tarifas de uso están ofrecido... son realmente ofrecido a los clientes industriales y comerciales. En ese documento define es TOU, TOU-P, TOU-T y uno en especial para industriales y clientes comerciales con una demanda mínima de un mega voltio amperes. Estos clientes, pues, pueden mover su carga pico a fuera de pico, añadir carga a sus

horas fuera de pico o reducir las cargas en sus horas de pico. Muy pocas industrias y comercios en Puerto Rico tienen una demanda de por lo menos 1 MVA. Estos límites entonces limitan la disponibilidad de este tipo de servicio y más aún, si uno sigue leyendo en el documento, más desconcertante aún está la otra tarifa, lo que llaman el "time of use" para el sistema de aire acondicionado con almacenamiento en frío. Estas tarifas aplican solamente para sistemas de aire acondicionado con almacenamiento de frío para industrias y comerciales. La limitación en que está es que los sistemas de aire acondicionado tienen que tener, por lo menos, una capacidad mínima de 25 toneladas y que el sistema de almacenamiento de frío pueda, por lo menos, desplazar 25 por ciento de la capacidad de frío en las horas fuera de pico. Adicional a esto, el cliente tiene que presentar un estudio que demuestre la carga que va a ser transferida a la hora fuera de pico y las estrategias y otro requerimientos que menciona el documento que se le van a pedir al cliente cuando vaya a allá. Como punto final, el consumo de la carga y la demanda de

los aires acondicionados como en almacenamiento en frío tiene que ser medido por separado de la carga al total del cliente. Una analogía para un sistema de TOU, si aprobamos el "smart metering" en Puerto Rico, asumiendo este mismo texto, sería, para el cliente residencial sería como sigue. Este servicio aplica exclusivamente para clientes residenciales con solamente el televisor del cliente residencial. Este televisor tiene que tener, por lo menos, 54 pulgadas de pantalla y tiene que ser usado solamente en las horas fuera de pico para ver el programa de David Letterman en CBS en vez del de Larry King en el siguiente. En conclusión, actualmente no tenemos unos TOU, tarifa fuera de uso, para la gran mayoría de nuestros clientes industriales y comerciales, contrario a la esencia y el propósito del EPACT 2005. Como ellos mencionan en la misma ley que haga un extracto y subrayo la parte en que ellos mencionan que "each utility shall offer each of its customer classes, and provide individual customers upon customer request a time based rate schedule". Okay. Entonces, finalmente el documento de PREPA no provee información suficiente para, a mi entender,

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para justificar la reluctancia de adoptar el EPACT 2005 en la sección 1252 en los "smart metering" y su estimado o su estudio está basado muchas veces en estimaciones, en lo que ellos entienden que debe ser. Porque, por ejemplo, cómo pueden esperar una baja tendencia a los clientes interesarle en estos sistemas, como ha ocurrido quizás en algunas partes del US mainland, del país como grande, si como quiera que sea aquí localmente no se ha hecho una encuesta para preguntar eso. Entonces, yo requiero de la Autoridad de Energía Eléctrica que provea un programa de "smart metering" para todos esos clientes como propuesto por la EPACT 2005. Este programa, claro, tiene que estar bien diseñado e implementado para asegurar que PREPA sea solvente con el mismo y que los clientes estén satisfechos. Este programa puede ser bien importante para nuestra economía maltrecha, para proveer incentivos a nuestros clientes industriales y comerciales para que ellos a su vez puedan proveer más oportunidades de empleo. Aparte de todo esto, todo cliente residencial debe disfrutar los beneficios de este sistema de "time based" de la misma forma que nosotros como clientes de celulares disfrutamos los

G00145

mismos las noches y los días de fines de semana. Así también, yo podría considerar cambiar mi cable tv, mi servicio de Direct TV a PREPA Direct TV si ellos me ofrecen un paquete de descuento, el cual incluye electricidad también. Esto es, me deja... sin dejar afuera que si la Autoridad de Energía Eléctrica está lista para instalar cables e internet a través de sus sistema de línea, estoy seguro que pueden buscar las maneras de cómo leer mi metro en una forma más eficiente. Eso es todo.

OFICIAL EXAMINADOR:

Muchas gracias al ingeniero Gerardo Cosme por su ponencia. Ingeniero Alfredo Huertas, ¿alguna pregunta para al ingeniero Cosme? Este servidor tampoco tiene preguntas; así que, puede retirarse, Ingeniero.

ING. GERARDO COSME NÚÑEZ:

Okay. Gracias a los presentes. Que tengan buen día.

PONENCIA DE ACONER-PR

OFICIAL EXAMINADOR:

Igual. Albith Colón, Walter Pedreira, ACONER. ¿Tiene una ponencia para nosotros?

*****

G00146

ING. ALBITH COLÓN:

¿Ustedes no la tienen?

ASESOR TÉCNICO:

¿ACONER es la compañía?

ING. ALBITH COLÓN:

Es una asociación.

ASESOR TÉCNICO:

Una asociación.

ING. ALBITH COLÓN:

Muy buenos días. Estamos aquí en representación de la Asociación de Consultores y Contratistas de Energía Renovable de Puerto Rico, ACONER Associates. Tanto el ingeniero Pedreira, como en este caso el ingeniero Colón, estamos en representación de algunos otros integrantes que no pudieron venir a las Vistas Públicas. Pertenecemos al Colegio de Ingenieros Electricistas de Puerto Rico, somos Ingenieros Profesionales. También pertenecemos a la Asociación de Internacionales de Energía o Asociación de Ingenieros de Energía, que ellos se dedican... es la Asociación de Energía Solar. Pertenecemos a la Asociación Internacional. De igual manera, al ... [ininteligible]. Estimado Oficial Examinador; estimado Asesor Técnico,

000147

ingeniero Alfredo Huertas; estimado y distinguido ingeniero Juan Alicea que se encuentra por la Autoridad de Energía Eléctrica y distinguidos deponentes. ACONER es una entidad... Vamos a dividirnos la ponencia. Trabajo de equipo.

ING. WALTER PEDREIRA:

Trabajo de equipo. ACONER-PR es una entidad de reciente creación en el año 2007 fundada con el objetivo principal de fomentar el desarrollo de la energía renovable en Puerto Rico. La Asociación busca a su vez contribuir con el desarrollo de esta emergente industria en colaboración con agencias de gobierno y otras entidades en términos de política pública sobre el tema. De igual manera, la ACONER-PR desea desarrollar un ambiente de competencia justa y educar a la industria, el comercio y el público en general. Bajo esta premisa, se presenta esta ponencia sobre los estándares de medición basada en tiempo y comunicación, sección 1252 "time based metering and communication" y de interconexión, sección 1254, "interconnection standard for distributed resources", según contemplado en la ley federal "Energy Policy Act of 2005" y sujeto a consideración y posible adopción

000148

por parte de la Autoridad de Energía Eléctrica. Antes de comenzar nuestra ponencia sobre el documento preparado por la División de Estudio y Planificación de la AEE en su informe publicado en junio del 2007 queremos comentar que es bien importante que se sepa que la política pública energética de Puerto Rico establecida en el 1993 recae sobre el Departamento de Asuntos de Energía. Por ende, es bien importante que se defina claramente si este plan de la Autoridad de Energía Eléctrica se está acatando en conjunto o en coordinación con el Departamento de Asuntos de Energía al igual que se defina como la ley del Public Utility Regulatory Act, PURPA, se relaciona con la política pública. A continuación presentamos nuestros comentarios sobre el documento preparado por la División de Estudios y Planificación de la Autoridad de Energía Eléctrica en su informe publicado en junio del 2007. Comentarios sobre la introducción. En primer lugar, queremos aclarar que la sección posterior a la definición del Public Utility Regulatory Act, página dos del reporte, en la sección de Costo Efectividad, se menciona que todos los propósitos de PURPA son importantes y se

interrelacionan. Pero en la subsiguiente oración se concluye: "cuando se cumplen al menos dos de los tres propósitos, se entiende que se alcanzan los propósitos de PURPA". ACONER-PR no está de acuerdo con esta conclusión, pues la misma se presta para que, por ejemplo, la Autoridad decida a tener programas de conservación y de optimización, pero no de tarifas equitativas. ACONER-PR recomienda que se sustituya la última oración diciendo que: "se deben cumplir los tres propósitos por los cuales se estableció PURPA en el 1978, para alcanzar objetivos de dicha ley con modificaciones en favor de promover nuevas tecnologías que reduzcan las dependencias de fuentes energéticas fósiles. A su vez, promoviendo reducción de contaminantes hacia el medio ambiente y contribuyendo a la reducción del calentamiento global." La sección B de "time based metering communication" la va a exponer el doctor Colón.

ING. ALBITH COLÓN:

Sección B, "time based metering and communication". ACONER Puerto Rico recomienda la adopción del estándar 1252, tal como lo recomienda la División de Estudio y Planificación de la Autoridad de

Energía Eléctrica en su informe publicado en junio del 2007. En el informe la Autoridad de Energía Eléctrica no recomienda que se aplique en este momento a nivel residencial, y enfatizamos y subrayamos en este momento a nivel residencial, por los costos asociados de infraestructura, el cual penalizaría basado en costos de instalación de nuevos equipos o reemplazo de estos equipos tanto al usuario como a las empresas de utilidad o la Autoridad de Energía Eléctrica. Sin embargo, la Autoridad de Energía Eléctrica y ACONER, Puerto Rico sí recomiendan que inicialmente se utilice... su utilización sea para tarifas industriales y comerciales. Finalmente, en clientes con tarifas basadas en el estándar 1252 a través de la inyección energética por fuentes renovables se pudiera observar un beneficio tanto como para el cliente como para la Autoridad de Energía Eléctrica con este tipo de tarifa. ACONER, Puerto Rico favorece la implantación del estándar a nivel residencial en el futuro cercano, posible tres a cinco años, una vez se pueda implantar, implementar tecnologías costo efectivas o medidas... o subsidio o financiamiento que permitan absorber los costos

000151

para tanto las residenciales como para la Autoridad de Energía Eléctrica. Nuestra organización está totalmente de acuerdo con la adopción de este estándar como un medio importante para ayudar a fomentar el desarrollo de alternativas de energía renovable. C, "interconnection standards for distributes resources". ACONER, Puerto Rico también recomienda la adopción del estándar 1254 tal como lo recomienda la División de Estudios y Planificación de la Autoridad de Energía Eléctrica en su primer informe publicado en junio del 2007. Se incluyen las siguientes recomendaciones que tienen como propósito minimizar las preocupaciones relacionadas a temas ya anteriormente cubierto con los estándares establecidos y ya en práctica en diferentes Estados de los Estados Unidos de Norteamérica. El estándar 1547 "DR Grid Interconnection" de la IEEE se usa para evaluación específica, diseño e instalación de sistemas de generación distribuida. Algunas de estas partidas cubren... algunas de las partidas que cubren son: contribución a corto circuito, coordinación de protecciones, regulación de voltaje, proceso de "islanding" o isla, sobrevoltajes y conexiones a

000152

tierra y situaciones de "network". De por sí este estándar se encarga de cubrir las preocupaciones e inseguridades citadas en las páginas 21 y 22 en las secciones que cubren seguridad confiabilidad del sistema y operación del sistema. También queremos añadir que si un cliente residencial, comercial o industrial se desea interconectar a la red eléctrica con un sistema fotovoltaico, esto sería conforme a un diseño eléctrico, según las áreas de relevancia por el Código Eléctrico Nacional, mejor conocido como el NEC, National Electrical Code. Ejemplo de ellos son: para módulos fotovoltaicos y paneles deben cumplir con el estándar UL 1703 "Flat Plate Photovoltaic Modules". Inversores controladores de carga deben cumplir con el UL 1741. La IEEE 929 prácticas recomendadas para interconexión entre utilidades y sistemas fotovoltaicos. Diseños de sistema e instalación deben cumplir con las siguientes: la IEEE 929, que anteriormente mencioné; la IEEE 1374, guías de seguridad para sistemas fotovoltaicos terrestres; la IEEE 937, prácticas recomendadas para sistemas de batería y sistema fotovoltaico; la IEEE 1145, prácticas recomendadas para sistemas de batería en

sistemas fotovoltaico una de níquel y otras de...[ininteligible]. Y la IEC 61215-61646. De igual manera ACONER, Puerto Rico recomienda la adopción de un reglamento técnico y procesal que fije un sistema de solicitud, evaluación y acuerdo final rápido, fácil y justo para ambas partes, tanto el cliente como la Autoridad de Energía Eléctrica, a la vez que se asegure la seguridad de las personas envueltas y la integridad del sistema eléctrico. Sólo de esta forma se puede lograr que la adopción de este estatuto se convierta en un paso importante en el desarrollo de energía renovable en Puerto Rico y no en un impedimento más. Para lograr esto, ACONER de Puerto Rico recomienda, al igual que la Autoridad de Energía Eléctrica en su informe de junio de 2007, que se adopte un reglamento basado en guías recomendadas por el "National Association of Regulatory Utility Commissioners" o NARUC en su informe del 2003. "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources". A continuación se enfatiza varios puntos fundamentales del estándar de NARUC que nuestra organización considera son de gran importancia para

G00154

poder lograr los objetivos de rapidez, claridad y justicia para ambas partes. Recomendamos identificar una agencia reguladora intermediaria que regule y fiscalice los acuerdos entre el "interconnection provider" y el "interconnection customer". Recomendamos que se establezca un sistema de solicitud y evaluación con criterios claros y con fechas límites para ambas partes durante el proceso "Super Expedited Review Process". Los criterios que incluyen el cumplimiento de los equipos de generación a ser interconectados con una serie de códigos y estándares conocidos en la industria por la IEEE, UL, NFPA y NEC, etcétera importantes para asegurar la seguridad del personal envuelta y la integridad del sistema de distribución eléctrica. Le recomendamos que se establezca un proceso de evaluación alterno para estudiar la viabilidad de interconexión en un sistema que no cumpla con los criterios del proceso inicial y sugerimos que se establezcan formas de aplicación claras y sencillas y divididas en clasificaciones de sistemas de generación. Solicitamos un acuerdo final entre ambas partes por medio de un contrato de

000155

interconexión. Y sexta, ACONER, Puerto Rico busca el establecimiento de cuotas justas y basadas en los costos reales incurridos por la Autoridad de Energía Eléctrica durante el proceso de solicitud y evaluación. Nuevamente, nuestra organización ACONER, Puerto Rico enfatiza en la creación de un proceso justo que fomente, no retarde, el desarrollo de las fuentes de energía renovable en la Isla. Y sin otro particular básicamente ésta es la ponencia de nuestro equipo.

ING. WALTER PEDREIRA:

No están con nosotros el ingeniero Ernesto Rivera de Renewable Engineering. Albith Colón de Energtech, el señor Lino Aponte de La Casa Solar y su servidor de Caribbean Renewable Technologies. Muchas gracias.

ING. ALBITH COLÓN:

Muchas gracias.

OFICIAL EXAMINADOR:

Yo quiero aclarar que he visto ayer y hoy que en las ponencias se tiende a entrar a lo que sería el proceso de reglamentación en caso de adoptarse e implementarse por parte de la Autoridad las secciones 1252 y 1254. Está muy bien. Sin

embargo, para que sepan todos los ponentes, aprovechar la oportunidad. En su momento de la Autoridad decidir implementarlo, se entraría en un proceso de reglamentación con vistas públicas que ése sí sería el momento en expresar, para récord y para que se tome en consideración el proceso de reglamentación, dicha sugerencia.

ING. ALBITH COLÓN:

Sí. Distinguido Oficial, lo quisimos traer como...

OFICIAL EXAMINADOR:

No, perfecto.

ING. ALBITH COLÓN:

Eran preocupaciones que aparecían en el documento que teníamos y ya hay maneras de aclarar esas preocupaciones. Por eso la quisimos traer a la ponencia.

OFICIAL EXAMINADOR:

Perfecto. Entonces, lo otro es a ver si me aclara en relación a la Sección B. Usted expresa que: "En el informe la AEE no recomienda que se aplique en este momento a nivel residencial", y que ustedes están de acuerdo son eso. Sin embargo, sigue y dice: "pero sí que se utilice para comercial e industrial". Sin embargo, la posición de la

G00157

Autoridad es que ya lo tiene.

ING. ALBITH COLÓN:

Por eso, pero estamos de acuerdo y estamos básicamente afirmando de que en este momento a nivel residencial en base a los costos asociados deberíamos retrasarlo en lo que se evalúe de una manera mucho más efectiva a nivel residencial.

OFICIAL EXAMINADOR:

Por eso. Lo que quiero es aclarar esa pala... Sí recomiendan que inicialmente, inicialmente, pero si yo lo analizo en el contexto global...

ING. ALBITH COLÓN:

Sí.

OFICIAL EXAMINADOR:

...yo no tendría que en esta etapa inicialmente porque de acuerdo a la posición de la Autoridad, que no necesariamente es la posición de otros ponentes, pero de acuerdo a la posición de la Autoridad, ellos con sus tarifas TOU ya están cubriendo lo que es la tarifa... este renglón para lo que es industrial y comercial. ¿Ustedes están en esa línea también?

ING. ALBITH COLÓN E ING. WALTER PEDREIRA:

Sí.

000158

OFICIAL EXAMINADOR:

Ésas eran mis preguntas. Muchas gracias.

ING. ALBITH COLÓN:

Gracias a usted.

OFICIAL EXAMINADOR:

Oficial Alfredo Huertas, si tiene preguntas.

ASESOR TÉCNICO:

Sí. Yo tenía una pregunta. Era relacionada básicamente con eso. Ustedes en cierta manera objetaban las razones que daba la Autoridad para el uso de TOU en la tarifa "time of use" para residencial.

ING. ALBITH COLÓN:

No, no... Bueno, a nivel residencial, a nivel residencial en este momento.

ASESOR TÉCNICO:

Pero mi pregunta iba encaminada si ustedes habían estudiado o tenían alguna objeción, o habían estudiado más a fondo las razones que la Autoridad da por las cuales entienden que en este momento no son... no es recomendable.

ING. ALBITH COLÓN:

No, si estamos de acuerdo con ustedes, por eso mismo. Estuvimos evaluando y entiendo que en este

C00159

momento costo efectivo no hace sentido a nivel residencial.

ASESOR TÉCNICO:

Okay. Debidamente aclarado. Gracias.

ING. ALBITH COLÓN:

Gracias. Buen día.

PONENCIA DE ARQ. FERNANDO ABRUÑA

OFICIAL EXAMINADOR:

Gracias a ustedes. Fernando Abruña, Colegio de Arquitectos y Arquitectos Paisajistas de Puerto Rico.

ARQ. FERNANDO ABRUÑA:

Buenos días a todos.

OFICIAL EXAMINADOR:

Buenos días.

ARQ. FERNANDO ABRUÑA:

Mi nombre es Fernando Abruña. Soy Arquitecto practicante; Director del Taller de Diseño Sustentable de la Escuela de Arquitectura de la Universidad de Puerto Rico; Presidente del US Green Building Council, Capítulo del Caribe; miembro de la American Institute of Architects, Capítulo de Puerto Rico y del Colegio de Arquitectos y Arquitectos Paisajistas de Puerto Rico,

C00160

organizaciones profesionales las cuales represento en esta vista y quienes me han autorizado para así hacerlo. Hacemos constar por este medio nuestro endoso y recomendación...

OFICIAL EXAMINADOR:

Con su permiso, Arquitecto, para efectos de récord, entonces usted está representando no solamente al Colegio de Arquitectos sino...

ARQ. FERNANDO ABRUÑA:

A esas dos organizaciones

OFICIAL EXAMINADORES:

Perfecto.

ARQ. FERNANDO ABRUÑA:

Al US Green Building Council y al American Institute of Architects, Capítulo de Puerto Rico.

OFICIAL EXAMINADOR:

Perfecto, adelante.

ARQ. FERNANDO ABRUÑA:

Hacemos constar por este medio nuestro endoso y recomendación para que se adopten los estándares "time based metering and communication", sección 1252 y el "interconnection standard for distributed resources", sección 1254 que forman parte del "Energy Policy Act" del año 2005, la cual enmendó

la Public Utility Regulatory Policy Act, PURPA, de 1978. Recomendamos también el que se aproveche la oportunidad y se apruebe la sección 1251 "net metering" ya que las tres están íntimamente relacionadas. Como marco de referencia, PURPA es la ley federal establecida en el año '78 que establece que la Autoridad de Energía Eléctrica tiene la obligación de comprar la energía de cogeneradores o pequeños productores de electricidad utilizando fuentes renovables al costo evitado. En 1983 la Autoridad de Energía Eléctrica publicó su reglamento titulado "Rates and Conditions of Service for Cogenerators and Small Electric Power Producers", el cual fue derogado a finales de la década de los '90. Desde esa fecha hasta el presente la Autoridad continúa con la obligación de cumplir con la Ley de PURPA, por lo que evalúa cada caso de forma individual por no tener un reglamento definido. Preámbulo a la sección 1252. El estándar 1252, conocido también como "smart metering" obliga a la Autoridad a considerar tarifas de uso por horario a sus clientes en todas sus clases. La fecha límite para determinar la implantación de "smart metering" es

000162

el 8 de agosto de 2007, menos de un mes a partir del día de hoy. Recomendamos el estándar "time based metering and communication", sección 1252 por las siguientes razones: este estándar permitirá que diferentes usuarios comerciales y residenciales entre otros puedan obtener una tarifa más baja de consumo en horas nocturnas o fuera de pico. Este tipo de estructura tarifaria abona a mejorar la viabilidad económica de fuentes renovables de energía como lo son los sistemas fotovoltaicos y sistemas eólicos que ya cuentan con varias instalaciones en la Isla. La Escuela Ecológica de Culebra, diseñada por nuestra oficina para la Autoridad de Edificios Públicos y el Departamento de Educación de Puerto Rico es uno de ellos. La estructura tarifaria que posibilita este estándar permitirá que los sistemas fotovoltaicos puedan generar electricidad durante el día cuando el consumo en la Isla y en la escuela es mayor y alimentarse de la red de la Autoridad durante la noche cuando el sol no está en nuestros cielos. Este estándar permite la instalación de sistemas de fuentes renovables de energía eliminando la necesidad de un banco de baterías equivalente a

000163

aproximadamente 25 por ciento del costo total de sistemas autónomos haciendolos, por lo tanto, más económicos. La eliminación de este costo acorta proporcionalmente el periodo de recobro de la inversión inicial haciendo más atractiva la opción de fuentes renovables de energía para la población en general. La eliminación del banco de baterías reduce además los gastos de mantenimiento y elimina el Talón de Aquiles de estos sistemas, ya que las baterías tienen una vida útil limitada si la comparamos con la larga duración de los paneles y abona, además, a la sustentabilidad ecológica de sistemas fotovoltaicos y eólicos ya que la disposición de las baterías supone un proceso de mitigación ambiental. Este estándar conocido comúnmente en inglés como "smart metering" prepara el terreno para que la Autoridad pueda facilitar la adopción del sistema de medición neta o "net metering", sección 1251, ahora. Aprovecho esta ocasión para declarar y solicitar públicamente a esta Autoridad que al aprobar la adopción de las secciones 1252 y 1254 adopte la sección 1251 y que permita y adopte el sistema de medición neta en la Escuela Ecológica de Culebra del Departamento de

Educación para el inicio del año escolar en agosto de 2007. La Autoridad está capacitada para hacer dicha conexión y el National Electrical Code, bajo el cual se diseñó el sistema, aborda y atiende las preocupaciones de seguridad en el sistema de interconexión que pueda tener la Autoridad. El Departamento de Educación es uno de los mayores deudores de energía de la Autoridad. Fomentar escuelas como la de Culebra que generen parte de su electricidad mediante el uso de energía solar no es sólo una política sabia para la Autoridad sino además para todo el sector consumidor en la Isla. Iniciar el sistema que propone la adopción del estándar 1252 facilitará el mantenimiento del sistema en la escuela. Más de 42 estados de la nación norteamericana han adoptado el sistema de medición neta, incluyendo las Islas Vírgenes que sufren condiciones de isla, costos elevados de generación y dependencia de la quema de petróleo como ocurre en Puerto Rico. Más de 30 organizaciones privadas profesionales y sin fines de lucro y personas de prestigio en el campo de la energía y la sustentabilidad nos han dado su endoso para que la Autoridad de Energía Eléctrica inicie

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un sistema de medición neta en la Escuela de Culebra. A continuación menciono alguno de ellos: el Colegio de Ingenieros y Agrimensores de Puerto Rico; el Colegio de Arquitecto y Arquitectos Paisajistas de Puerto Rico; el American Institute of Architects, Capítulo de Puerto Rico; el US Green Building Council, Capítulo del Caribe; Casa Pueblo en Adjuntas; Georgie Bernardette de Al Gore Climate Project; la Sociedad de Historia Natural de Puerto Rico; la Alianza Ciudadana para la Educación en Educación en Energía Renovable; Emerging Green Builders, Capítulo del Caribe; Sierra Club de Puerto Rico; Misión Industrial de Puerto Rico; la Escuela de Arquitectura de la Universidad de Puerto Rico; el Fondo de Mejoramiento de Puerto Rico; el doctor José Molinelli de Ciencias Ambientales de la Universidad de Puerto Rico; el doctor David Serrano, Director del Carro Solar del Colegio de Mayagüez; el arquitecto Jorge Ramírez, codirector del Décalo Solar del 2007; el ingeniero Ángel Zayas, Presidente del Comité de Diseño de la Sociedad de Ingenieros Electricistas; Alexis Molinares, Ecólogo; María Juncos Gautier, Centro de Estudios Sustentables de la UMET; el doctor Gerson

000166

Beauchamp de Ingeniería Eléctrica del Colegio y del Décalo Solar 2005; el ingeniero Eduardo Cosme de Solartek; ingeniero Eduardo Tobaja de Advance Technology Products; el doctor Colón Negrón de Energtech; Eduardo García de TecnoSun; Vadim Nikitine de Commercial Centers Management; Lino Aponte de Casa Solar; el ingeniero Felipe Bermúdez de IB Homes; el arquitecto Vincet Pieri y el arquitecto Luis Huertas, ambos LEED Acredited Professional; Diego Sorroche Fraticelli de Puerto Rican Appraisers; Carmen Pura Rodríguez, Educadora Ambiental de la Universidad del Sagrado Corazón; Yahaira Graxirena del Habitat Urbano y múltiples ingenieros y arquitectos de Puerto Rico. Aunque entendamos que la Autoridad tiene hasta agosto de 2008 para demostrar por qué puede o no adoptar un sistema de medición neta, exhortamos a la Autoridad a que inicie este programa ahora en la escuela, aunque sea sólo inicialmente en los edificios del gobierno como un gesto de su deseo y disponibilidad de promover fuentes alternas de energía en Puerto Rico. El ahorro de una agencia se compensa con el alegado costo adicional sobre el costo evitado que la Autoridad ha argumentado en el pasado. Lo justo

000167

y esperado por la comunidad consumidora es que la Autoridad venda y compre energía eléctrica de usuarios como lo es esta escuela al mismo precio. La Autoridad de Energía Eléctrica podía dar un buen ejemplo de su compromiso con el futuro energético y ambiental del país haciendo una excepción a su política actual instalando un sistema de medición neta en la primera Escuela Ecológica de Puerto Rico, considerando que la escuela es patrimonio del estado, entendemos que esta concesión de la Autoridad a la escuela no debe de ser difícil de justificar ni de implantar. Estamos en espera de una acción positiva por parte de la Autoridad de Energía Eléctrica para que se instale un sistema de medición neta en la Escuela Ecológica de Culebra y que apruebe la sección 1251, "net metering", a la misma vez que adopte las secciones 1252 y 1254, las cuales su numeración así lo evidencia, están íntimamente ligadas. Preámbulo a la sección 1254. Le ley federal de 2005 obliga a la Autoridad a considerar adoptar el estándar IEEE 1547 del año 2003 como estándar nacional de interconexión. El propósito del estándar es uniformar el proceso de interconexión entre compañías eléctricas y entre

000168

estados. No obstante, toda compañía eléctrica sujeta a PURPA de alguna forma tiene o ha manejado el proceso de interconexión. La fecha de cumplimiento es el 8 de agosto de 2007 para aceptar o no el estándar nacional. De no aceptarlo, la Autoridad debe justificarlo al Federal Energy Regulatory Commission, FERC. Nuevamente y de forma análoga con la sección 1252 la fecha límite para determinar le implantación de la sección 1254 es el 8 de agosto del 2007, a menos de un mes a partir del día de hoy. Recomendamos el estándar Interconnection Standard for Distributed Resources, sección 1254 por las siguientes razones: según PURPA desde el año 1978 debe existir una guía de interconexión desarrollada por cada Estado. Han pasado casi 20 años desde el inicio de PURPA y muchos de los 50 estados de la nación norteamericana ya han adoptado este estándar nacional para evitar potenciales problemas entre las compañías que ofrecen el servicio eléctrico, "utilities", y los estados. Este estándar se basa a su vez en el estándar 1547 del Institute of Electrical and Electronic Engineers, IEEE, titulado "Standard for Interconnecting Distributed Resources

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with the Electric Power System". El estándar ya está escrito y ha sido puesto a prueba en múltiples Estados. La Autoridad de Energía Eléctrica puede adoptar ese estándar fácilmente y es de acceso a todos los profesionales que se involucran en el diseño e instalación de estos sistemas. Según las referencias consultadas, y tengo entonces una lista de referencias al final del documento, el estándar 1254 permitirá aumentar el uso eficiente de combustibles, aumentar la calidad de la electricidad y seguridad de la red de distribución, proveer un servicio más confiable, aplicar generación especializada y mitigar los déficit de generación. También permitirá reducir costos operacionales a la Autoridad y a sus clientes, reducir emisiones y contaminación a nivel global, atender asuntos de calentamiento global y de emisiones al ambiente, respaldar la generación por medio de fuentes renovables de energía, atender asuntos de seguridad y, a la vez, ofrecer mayor seguridad en la estabilidad de los precios de combustible. El mismo abona también a viabilizar el sistema de "net metering" en Puerto Rico. Endosamos y recomendamos las secciones 1251, 1252 y

000170

1254 que forman parte del Energy Policy Act del año 2005 porque la cantidad de energía que se recibe del sol o del viento no es constante, es intermitente. El consumidor no consume la energía necesaria en el momento que se genera. Estas medidas le facilitarán a los consumidores recibir el valor completo por la electricidad que producen sin instalar costosos sistemas de almacenamiento en baterías. Estas secciones también ayudarán a proveer un mecanismo de fácil administración económico y simple a la vez que ayudará a promover el uso sistemas alternos de energía, tales como generadores eólicos y paneles fotovoltaicos, los cuales proveen importantes beneficios locales, nacionales y globales al ambiente y a la economía. Casi todos los estados han adoptado estas dos secciones y el sistema de medición neta 1251. No podemos pensar que Puerto Rico tenga que ser la excepción a la regla. La Autoridad puede demostrar parte de su compromiso con las fuentes alternas de energía, un mejor ambiente y la descentralización de la generación de electricidad en Puerto Rico adoptando estas dos secciones y el sistema de medición neta ahora. Existe la masa crítica y el

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deseo de la comunidad profesional, académica y el público general de que Puerto Rico pueda desarrollar su potencial energético utilizando fuentes alternas de energía menos dañinas al ambiente y que la actual quema de combustible fósil utilizada por la Autoridad como fuente principal en su proceso de generación. En resumen, recomendamos la adopción no sólo de las secciones 1252 y 1254 sino además de la sección 1251 "net metering" ahora. Y entonces, aparecen la lista de referencias consultadas en la preparación del documento. Eso es todo. Le doy las gracias por permitirme dirigirme a ustedes y al público.

OFICIAL EXAMINADOR:

Gracias a usted por su asistencia. Ingeniero Alfredo Huertas, ¿alguna pregunta para el arquitecto Abruña? No tengo preguntas; así que, puede retirarse.

ARQ. FERNANDO ABRUÑA:

Muy amable, gracias.

PONENCIA DEL ING. JORGE EL KOURY

OFICIAL EXAMINADOR:

Jorge El Koury, Cámara de Comercio.

*****

ING. JORGE EL KOURY:

Muy buenos días.

OFICIAL EXAMINADOR:

Buenos días.

ING. JORGE EL KOURY:

Mi nombre es el ingeniero Jorge El Koury y comparezco en representación del Comité de Energía de la Cámara de Comercio de Puerto Rico.

OFICIAL EXAMINADOR:

¿Tiene copia de la...

ING. JORGE EL KOURY:

No. Tengo escrito, pero si quiere se lo puedo... Es par de líneas nada más.

OFICIAL EXAMINADOR:

Adelante.

ING. JORGE EL KOURY:

La Cámara de Comercio de Puerto Rico favorece toda iniciativa que redunde en reducir los costos de energía eléctrica, mejorar la confiabilidad y proveer una energía eléctrica producto de baja o ninguna emisión ambiental como lo son las fuentes renovables y la eficiencia energética. Entendemos que los estándares 1252 y 1254 establecidos en el Energy Policy Act del 2005, conocido como el

G00173

EPACT05 cumplen con dicho objetivo. Muchas gracias.

PONENCIA DEL SR. JOHN MILLER

OFICIAL EXAMINADOR:

John Miller y Paul Marvin.

SR. JOHN MILLER:

No, solamente John Miller.

OFICIAL EXAMINADOR:

John Miller, ¿Alianza Comunitaria?

SR. JOHN MILLER:

Sí. Buenos días al señor Oficial Examinador.

OFICIAL EXAMINADOR:

Buenos días.

SR. JOHN MILLER:

Buenos días a la audiencia. Quien les habla es el señor John Miller representando en esta ocasión a la Comisión Coordinadora de la Alianza de Organizaciones Comunitarias y Ambientales en Acción Solidaria, mejor conocida como ACAAS. Luego de varios encuentros fraternales para el diálogo y el análisis sobre las necesidades que enfrenta al pueblo puertorriqueño con respecto al desarrollo comunitario y cuestiones ambientales, hemos organizado dicha Alianza a nivel nacional que tiene como visión un Puerto Rico de desarrollo

sustentable comunitario, justicia social y protección ambiental plena, teniendo como eje articulador la dignidad de la persona humana, la consciencia y responsabilidad social, la familia y la nación puertorriqueña. Además, nuestra misión es crear un compromiso integral y participativo de los grupos ambientales y comunitarios para lograr efectivamente la elaboración y aplicación de nuevas y mejores leyes protectoras del medio ambiente en Puerto Rico. En este sentido, tenemos como objetivo general el promover que se cumplan las leyes que efectivamente protegen el medio ambiente en el país, de educar y orientar a las comunidades acerca de temas ambientales y crear un frente amplio e integral para enfrentar acciones y procesos que amenacen nuestros recursos naturales y la salud de los puertorriqueños. El sueño propuesto es un modo de vida sustentable fruto del cuidado para todo ser, especialmente para con todas las formas de vida y de responsabilidad colectiva frente al destino común de nuestra tierra y nuestra gente. Así, la coyuntura histórica que vive Puerto Rico se convierte hoy en un desafío que requiere una respuesta urgente desde la más amplia

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solidaridad. Como parte de esa gestión solidaria y compromiso social por Puerto Rico, hoy deseamos exponer nuestras ideas, análisis y reclamaciones sobre EPACT 2005. Lo primero que le solicito en vista de lo que hemos escuchado anteriormente aquí es que nos permitan la oportunidad de hacer un addendum a nuestra exposición y ya van a ver por qué razón, de las cosas que voy a exponer. Aquí se ha reclamado que FERC, el ente regulador para esta ley. FERC lo que hace en su Ley Orgánica, conforme a su Ley Orgánica, es que delega la autoridad para reglamentar a las autoridades estatales. En Puerto Rico no hay ninguna entidad estatal que reglamente para los efectos del EPACT 2005 o para PURPA. La Administración de Asuntos de Energía solamente tiene potestad sobre la Autoridad de Energía Eléctrica en cuanto a su Ley Orgánica respecto al aumento de capacidad por generación. Por lo tanto, si generan más de un mega vatio que va a aumentar, tiene que pasar por la autorización de la Administración de Asuntos de Energía. Pero todo lo que sea en términos de tarifa y costos y demás, la Administración de Asuntos de Energía no tiene ninguna jurisdicción. En términos de lo que la

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Autoridad planteó en su ponencia sobre esta gráfica, nos llamó la atención por varias cosas desde el punto de vista técnico. Número uno, de que se ha escogido o un día, o un mes de un año; no se ha escogido un periodo de tiempo. En inglés, eso se podría denominar como una especie de "...[ininteligible]...", o sea, yo soy selectivo y voy a presentar lo que me es conveniente presentar. No obstante a eso que se ha planteado ahí, si usan la mentalidad de ingeniero y dicen que dado las siguientes circunstancias, pues entonces uno puede llegar a unas conclusiones sin tener que entrar en la parte técnica. Primer dado, que las plantas de energía termal son menos eficiente cuando las temperaturas de ambiente son elevadas. Nosotros vivimos en un país tropical. La temperatura elevada prevalece en Puerto Rico. Dado número dos. Dado que en nuestro ciclo solar es alrededor del mediodía donde la temperatura ambiental es la más elevada y que es más baja cuando baja el sol, que es durante la noche. Dado número tres. Que el estándar de PURPA que requiere que las compañías de generación eléctrica aumente su eficiencia en base de la generación, usando combustible fósil,

entonces, por lo tanto, cualquier programa que promueva lo que se llama como DSM, relativo al día de... a la parte del día que corresponde, mejoraría grandemente la generación, la eficiencia de la Autoridad de Energía Eléctrica si se cambian las cargas para por la noche cuando los generadores son más eficientes. Recomendación. Que se implemente "smart metering", contrario a la recomendación de la Autoridad, para permitir que el TOU, la tarifa TOU, al aplicarse directamente a los clientes pueda ser de tal forma que el costo de la generación de la Autoridad de Energía Eléctrica disminuya. Vamos a coger un ejemplo específico. El año pasado en diciembre se quemó la planta generatriz de Palo Seco. Ahí tenemos 600 mega vatios. Si nosotros tuviésemos en el día de hoy "smart metering", nosotros nos permitiría tener una estructura de precio que ajustaría durante estos periodos de problemas que tenemos con la planta para aportar al sistema y ser costo efectivo. No creo que la situación de Palo Seco vaya a ser una sola ocasión; podría ser algo repetitivo. Ahora, entrando de lleno a nuestra ponencia, además de la Ley Orgánica de FERC y la Ley Orgánica de la Administración de

000178

Asuntos de Energía, nosotros utilizamos el National Regulatory Research Institute, el "briefing paper" que ellos publicaron cuando salió el EPACT 2005. Y ha sido nuestra referencia sobre este particular. Las secciones 1251, 1252 y 1254 del subtítulo E de EPACT 2005 enmienda las secciones 111(d) y 112 del Public Utility Regulatory Policies Act del 1978, mejor conocido como PURPA. En el caso de la Autoridad de Energía Eléctrica estas enmiendas requieren que la Autoridad de Energía Eléctrica considere y determine los siguientes estándares dentro de unas fechas específicas. "Net metering", "smart metering", "interconnection", y se lo voy a leer en inglés porque es mejor que la traducción, "utility plans to minimize dependence on one fuel source" y "utility 10 year plans to increase efficiency of fossil fuel generation". Dichas enmiendas a PURPA fomentan el uso eficiente de nuestros recursos energéticos, inclusive los recursos relacionados a la demanda donde lo que prevalece son aumentos en precio. EPACT 2005 requiere que la Autoridad de Energía Eléctrica considere maneras específicas de fomentar que sus usuarios conecten generadores de pequeña escala a

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su red con capacidades de "net" o "advanced metering" y que permitan que el exceso de electricidad suministrada a su red del generador compense la electricidad extraída de la red por el usuario en otras ocasiones y, por lo tanto, reduzca la cuenta a pagar por el usuario. Esto crea un incentivo adicional económico para que los usuarios de la Autoridad de Energía Eléctrica se conviertan en generadores de energía y así favorezcan sus bolsillos. De no cumplir la Autoridad de Energía Eléctrica con los requisitos de establecer estos cinco estándares, entonces entrará en vigor la sección 112 © de PURPA que requiere que la consideración y determinación se lleve a cabo con el procedimiento del primer caso de tarifa comenzando después de la fecha límite. Esperamos que los usuarios de la Autoridad de Energía Eléctrica no se vean obligados a utilizar este procedimiento. A continuación le recordamos a la Autoridad de Energía Eléctrica el horario para considerar y determinar la adopción de los cinco nuevos estándares de PURPA: "net metering", comenzar consideración no más tardar de agosto 8, 2007 y llegar a la determinación no más tardar de

000180

agosto 8 del 2008. "Smart metering", llegar a la determinación no más tardar de agosto 8, 2007. "Interconnection", llegar a la determinación no más tardar de agosto 8, 2007. "Fuel sources", comenzar consideración no más tarde de agosto 8, 2007 y llegar a la determinación no más tardar de agosto 8, 2008. "Fossil fuel generation efficiency", comenzar consideración no más tardar de agosto 8, 2007 y llegar a la determinación no más tardar de agosto 8, 2008. La sección 1251(a)(11) requiere que la Autoridad de Energía Eléctrica provea al ser solicitado los servicios de "net metering" a cualquier usuario de la Autoridad de Energía Eléctrica. Efectivo hoy, este servidor le requiere oficialmente a la Autoridad de Energía Eléctrica que le provea el servicio de "net metering" y espero que la Autoridad de Energía Eléctrica responda oficialmente este requerimiento. Además, la ACAAS y este servidor en su carácter personal le requiere a la Autoridad de Energía Eléctrica el fiel cumplimiento y la implantación de los estándares de "smart metering" y "interconnection" en el año 2007 y los estándares de "net metering", "fuel sources" y "fossil fuel generation

C00181

efficiency" en el 2008. Estaremos atentos y pendientes y de no considerarse e implantarse los cinco estándares, se procederá para que se invoque la sección 112 © de PURPA. Nuestro compromiso en este asunto es con todos los sectores de nuestro pueblo y, por lo tanto, actuaremos según sea necesario dentro de nuestro sistema democrático y constitucional para que se lleve a cabo el fiel cumplimiento de EPACT 2005 en beneficio de todo nuestro pueblo.

OFICIAL EXAMINADOR:

Muchas gracias. El ingeniero Huertas tiene una pregunta para usted.

ASESOR TÉCNICO:

Al comienzo de su exposición, me pareció entender que usted dijo que la Autoridad en su análisis del uso la tarifa "time of use" TOU usó un solo día. Me extra... O sea, no entendí bien eso. ¿Qué es lo que usted quiso que...

SR. JOHN MILLER:

Lo que yo dije es que de la gráfica que se utilizó en la ponencia de la Autoridad...

ASESOR TÉCNICO:

Unjú.

C00182

SR. JOHN MILLER:

...en vez de coger un periodo de tiempo prolongado...

ASESOR TÉCNICO:

¿Cuánto usted llama prolongado?, porque entiendo que tiene ahí varios años.

SR. JOHN MILLER:

Bueno, por lo menos, en esa gráfica ahí está el mes de septiembre 2006, un mes. Ahí está un día típico, un día. Y en el otro está septiembre 2006; por lo menos, de las que yo vi ahí.

ASESOR TÉCNICO:

Porque yo entendía que está... hay un año de uso. ¿No es así, Sonia?

SR. JOHN MILLER:

Yo me dejé llevar por esas gráficas que están ahí.

ASESOR TÉCNICO:

Es que son varias gráficas.

SR. JOHN MILLER:

Sí, pero cuando usted coge un día típico y usa la matemática y dice que es cuatro años, eso usted llegó a un estudio estadístico o es porque si usted ve la gráfica durante todos esos días y todos esos años, usted no va a ver la misma gráfica de la

misma forma. Para usted poder determinar, por ejemplo, las cargas de alguna empresa, usted debe tener, por lo menos, en base de incremento de cada quince minutos, un bloque de quince minutos donde usted puede estudiar todas esas estadísticas para usted poder determinar cuál es la carga real de que está incurriendo esa empresa. El mensaje que yo estoy tratando de señalar aquí es que para poder apoyar y sostener la posición de la Autoridad de Energía Eléctrica para no apoyar el estándar de "smart metering", pues se usan unas gráficas que proyectan la posición de no favorecer "smart metering".

ASESOR TÉCNICO:

O sea, que usted cree que la muestra que está cogida está, este...

SR. JOHN MILLER:

Está viciada; está viciada.

OFICIAL EXAMINADOR:

Ésa es la posición de él.

ASESOR TÉCNICO:

Muchas gracias.

OFICIAL EXAMINADOR:

Muchas gracias al señor John Miller por su

C00184

ponencia. Puede retirarse. Yo le voy a pedir que me den cinco minutos para ir al baño, regresar y continuamos. ¿Está bien?

--RECESO--

OFICIAL EXAMINADOR:

Les doy las gracias por los cinco minutos. Vamos a continuar con los procedimientos de la vista. Le corresponde el turno al ingeniero Juan A. Pérez y Enrique Suco.

PONENCIA DEL ING. JUAN A. PÉREZ GONZÁLEZ

ING. JUAN A. PÉREZ GONZÁLEZ:

Siaca.

OFICIAL EXAMINADOR:

Siaca, perdone.

ING. JUAN A. PÉREZ GONZÁLEZ:

Y el ingeniero Peter Sinz.

OFICIAL EXAMINADOR:

Y el ingeniero Peter Sinz del Colegio de Ingenieros Agrimensores de Puerto Rico. Adelante.

ING. JUAN A. PÉREZ GONZÁLEZ:

Buenas tardes. Conforme a la ley que lo creó, Ley Número 319 del 15 de mayo de 1938 según enmendada, el Colegio de Ingenieros y Agrimensores de Puerto Rico que agrupa alrededor de 12,000 colegiados e

interviene en estos procedimientos administrativos por medio de éste que le habla, ingeniero Juan Antonio Pérez González, licencia número 6709, me acompaña también el ingeniero Enrique Siaca Esteves y el ingeniero Peter Sinz. Acorde con lineamientos regulatorios del Colegio y con el propósito de este procedimiento, cito algunos trozos del reglamento vigente como sigue: Artículo 2. El Colegio tendrá como fines principales lo siguiente, fomentar el bienestar de la comunidad, contribuir al adelanto y defensa de las profesiones de ingeniería y agrimensura y propender el mejoramiento del ejercicio profesional y el bienestar de sus miembros. Sus facultades y deberes, el Artículo 3, conforme a los fines anteriormente señalados y a las facultades y derechos conferidos por ley, corresponde a este Colegio velar por los intereses y bienestar de la comunidad puertorriqueña; salvaguardar y proteger los derechos de sus miembros en todo lo que se refiere al ejercicio de su profesión; asesorar al estado en asuntos de su competencia, promover el embellecimiento, mejoramiento ambiental de la comunidad puertorriqueña y pronunciarse en torno a cuestiones

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de interés público en aquellos asuntos que se consideran de su competencia. En ánimo constructivo hago un resumen ejecutivo y, a la misma vez, le hago entrega, ya le hice entrega de nuestra ponencia escrita. El Energy Policy Act 2005, EPACT 2005, requiere la consideración de una serie de estándares que están relacionados y que en conjunto pueden adelantar significativamente los propósitos de PURPA. Al presente, la Autoridad de Energía Eléctrica está considerando dos de estos estándares, el de interconexión y el de medición inteligente. El Colegio de Ingenieros y Agrimensores de Puerto Rico respalda la adopción del estándar de interconexión y nos alegramos que la Autoridad de Energía Eléctrica esté dispuesta a dar este primer paso. En específico, recomendamos la adopción del estándar IEEE 1547 así como los estándares de NARUC que atienden todas las preocupaciones mencionadas por la Autoridad de Energía Eléctrica en su informe de Consideración de los Estándares de EPACT 2005 "time based metering and communication interconnection standard for distributed resources". Además, la Autoridad de Energía Eléctrica debe atender los siguientes

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puntos. La Autoridad de Energía Eléctrica debe dejar establecido los requerimientos de medición para la interconexión así como el precio y demás términos y condiciones para la compra del excedente de electricidad producido por los generadores distribuidos. La Autoridad de Energía Eléctrica debe dejar establecido el arbitraje como alternativa para la resolución de disputas sobre interconexión. A tales efectos, sugerimos que se utilice el recurso de expertos técnicos o "technical masters" sugeridos por NARUC. La Autoridad de Energía Eléctrica debe adoptar el procedimiento expedido de interconexión para facilidades de generaciones pequeñas certificadas no mayores de 10 kilo watts y basadas en inversores que ha adoptado el Federal Energy Regulatory Commission. El último punto es particularmente importante, ya que dicho procedimiento es el que aplicaría a los abonados residenciales que son el 91 por ciento de los abonados de la Autoridad de Energía Eléctrica. El CIAPR también entiende que el segundo estándar de medición inteligente constituye el próximo paso importante para adelantar los propósitos de PURPA y que debe

000188

hacerse el esfuerzo de adoptar una o más de las opciones que el EPACT 2005 requiere considerar. Sin embargo, la Autoridad de Energía Eléctrica no ha mostrado los datos específicos necesarios que requiere la consideración de dicho estándar y no estamos de acuerdo con que se excluya a los abonados residenciales de todas las opciones. El EPACT 2005 requiere la evaluación individual de cada una de las alternativas de medición para cada una de las clases de servicio. Entendemos que esa evaluación detalla debe llevarse a cabo de forma que se adopten las opciones más apropiadas a tenor con dicha evaluación en conformidad con PURPA y la Ley 83. El Colegio de Ingenieros y Agrimensores de Puerto Rico está en la mejor disposición de ayudar a la Autoridad de Energía Eléctrica a cumplir a cabalidad con los requisitos del EPACT 2005 y a completar una evaluación adecuada de este segundo paso tan importante. Como un paso en la dirección positiva el Colegio ha comenzado a considerar los elementos necesarios para instalar un proyecto fotovoltaico en su propiedad que sirva para demostrar e ilustrar a sus miembros sobre la madeja de repercusiones económicas, deseables e

C00189

indeseables, y sobre los beneficios ambientales y de salud pública que traen ésta y otras tecnologías renovables. Guiar a instituciones hoy en precario, como hospitales, escuelas, a sobrevivir los actuales costos de energía. Ilustrar a los honorables miembros de las ramas Ejecutiva y Legislativa del Gobierno de Puerto Rico sobre opciones tecnológicas maduras para explotar económicamente fuentes de energía nativa, inagotable y limpia a tenor con las leyes número 83 del 2 de mayo de 1941, la ley número 128 del 29 de junio del 1977 que constituyeron a la Autoridad de Energía Eléctrica y a la Administración de Asuntos de Energía, respectivamente. Sometemos para el récord el informe del CIAPR que recoge las recomendaciones antes discutidas y urgimos nuevamente a la Autoridad de Energía Eléctrica a considerar el conjunto de los estándares de EPACT 2005 a los efectos de que se implante una sana política pública energética en Puerto Rico. Muchísimas gracias.

OFICIAL EXAMINADOR:

Gracias al Presidente del Colegio de Ingenieros y Agrimensores de Puerto Rico, Juan Antonio Pérez,

C00190

por su ponencia y a sus acompañantes, ingeniero Siaca e ingeniero Sinz. Alfredo Huertas, ¿tiene alguna pregunta para el Presidente?

ASESOR TÉCNICO:

No tengo preguntas.

OFICIAL EXAMINADOR:

Tampoco tengo preguntas. Muchas gracias nuevamente por su asistencia. Héctor Arana. ¿Héctor Arana no se encuentra?

PONENCIA DEL SR. HÉCTOR ARANA

VOZ NO IDENTIFICADA:

Estaba por ahí.

OFICIAL EXAMINADOR:

¿Alguien lo conoce que lo...

SR. HÉCTOR ARANA:

Arana.

OFICIAL EXAMINADOR:

Arana por aquí. Buenas tardes ya, señor Arana. Puede comenzar con su ponencia.

SR. HÉCTOR ARANA:

Gracias. Buenas tardes igualmente. Antes de entrar en mi ponencia escrita, estoy interviniendo en estas vistas públicas, como dice el Exhibit 1, como interventor. En el Exhibit 1 de mi ponencia yo

C00191

sometí a manuscrito mi solicitud de participar en estas vistas ayer, en la División Jurídica y en la División de Planificación. Y se me envió tarde en la tarde un fax cual... respondiendo a una solicitud de información que forma parte del expediente, en especial el estudio de EPRI y hay otros asuntos más que voy a tocar en la ponencia. Voy a entrar próximamente en mi ponencia escrita. Primero, leyendo la documentación que he podido obtener de la Autoridad de Energía Eléctrica, específicamente la propuesta que está publicada en el internet, yo le digo completamente, de hecho, un sinnúmero de análisis míos y una copia de la ponencia que va a presentar o ha presentado, y perdonen que llegué tarde, el ingeniero Juan Alicea Flores, Director de Planificación y Protección Ambiental en donde la Autoridad de Energía Eléctrica adopta el estándar e interconexión. Está claro en eso. Pero la Autoridad de Energía Eléctrica en el 1983, que llevó a cabo un procedimiento que voy a tocar en mi ponencia escrita, y están los exhibits a los efectos, específicamente resoluciones de la Junta de Gobierno de la Autoridad de Energía Eléctrica a

C00192

estos efectos de los estándares de PURPA, la Autoridad de Energía Eléctrica adoptó un sistema de interconexión y fue más lejos, presentó los diagramas de cómo esa interconexión se debió haber aceptado por la Autoridad de Energía Eléctrica. Que este estándar de interconexión desde 1983 fue formalmente adoptado por la Junta de Gobierno de la Autoridad de Energía Eléctrica, pero en práctica no lo llevó a cabo. Yo llevo, como van a encontrar en mi ponencia, desde el 2003 todos los planos aprobados por la Autoridad de Energía Eléctrica de interconexión de un molino de viento residencial de 1kw, que lo único que produce son 350, 400 kilovatios hora al mes cuando hay viento, meses ventosos. Que tiene una capacidad menor que una bomba de agua de una piscina y todavía no ha concluido eso. Y estamos todavía en el Exhibit 10 que va a encontrar una carta fechada el 20 de abril de 2007 de la señora Yoamarie Figueroa, Ayudante Ejecutiva del Directorado y Protección Ambiental donde estamos paralizados, como dice en el segundo párrafo de su carta, "que está pendiente de la evaluación de la Oficina de Administración de Riesgos, por lo que más adelante le notificaremos

los requisitos de seguros que se incluirán en el mismo". Todo ese trasfondo que le acabo de dar, antes de entrar en mi ponencia, que voy a entrar ahora, va directamente en conexión con la posición de la Autoridad de Energía Eléctrica a los efectos que en la ponencia que va a presentar el ingeniero Alicea Flores, que en la última página de su ponencia, en la página 11 dice: "la Autoridad entiende que debe adoptar el estándar de interconexión para generación distribuida que cumpla con lo establecido en el Interconnection Standard...". ¿Cuánto tiempo más va a tomar la Autoridad de Energía Eléctrica de aprobar finalmente el plano que aprobó de interconexión de ese molino de viento de 1kw? Vamos a entrar, que lo que me preocupa sí vamos a adoptar interconexión, ¿pero el procedimiento de evaluación de la Autoridad de Energía Eléctrica nos va a tomar diez años más? Voy a entrar en mi ponencia. Mi ponencia está en inglés porque esto es un asunto federal y la decisión final que tome la Autoridad de Energía Eléctrica mediante su Junta de Gobierno puede ser revisada ante un tribunal. Y es en inglés porque como es una ley federal, será revisada en el

C00194

Tribunal Federal, Distrito de Puerto Rico. Comenzaremos. "My name is Hector Arana, residential electric consumer of Puerto Rico Electric Power Authority, account number 01405304170019. At 10:39 AM of July 9, 2007 I presented hand written request to participate in this Hearing of PREPA. Exhibit one copy of hand written request to participate. In the event that no opposition is presented, I will proceed with my participation in this Public Hearing as a formal intervener pursuant 16 US Code, Section 2631, intervention in proceedings (A) Authority to intervene and participate". Y cito esa sección del US Code. "In order to initiate and participate in the consideration of one or more of the standards established by subchapter II of this chapter or other concepts which contribute to the achievement of the purposes of this chapter, the Secretary, any affected electric utility, or any electric consumer of an affected electric utility may intervene and participate as a matter of right in any rate making proceeding or other appropriate regulatory proceeding relating to rates or rate design which is conducted by a State regulatory authority with

C09195

respect to an electric utility for which it has rate making authority or by a nonregulated electric utility as PREPA. (B) Access to information. Any intervener or participant in a proceeding described in subsection (a) of this section shall have access to information available to other parties to the proceeding if such information is relevant to the issues to which his intervention or participation in such proceeding relates. Such information may be obtained through reasonable rules relating to discovery of information prescribed by the State regulatory authority in the case of a proceedings concerning electric utilities for which it has rate making authority or by the nonregulated electric utility in the case of a proceeding conduced by a nonregulated electric utility. The most important aspect of this Public Hearing is the applicability of the Laws of the Commonwealth of Puerto Rico to 16 US Code, Section 2623, PURPA Section 113, adoption of certain standards. (A) Adoption of standards. Not later than two years after November 9, 1978 each State regulatory authority with respect to each electric utility for which it has rate making authority and each nonregulated

C00196

electric utility shall provide public notice and conduct a hearing respecting the standards established by subsection (b) of this section and, on the basis of such hearing, shall 1, adopt the standards established by subsection (b) of this section other than paragraph four thereof if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate to carry out the purposes of this chapter, is otherwise appropriate, and is consistent with otherwise applicable State law, and to adopt the standard established by subsection (b)(4) of this section if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate and consistent with otherwise applicable State law. For purposes of any determination under paragraphs one or two and any review of such determination in any court in accordance to section 2633 of this title, the purposes of this chapter supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt

C00197

any such standard, pursuant to its authority under otherwise applicable State law." Pero tiene que dar una explicación escrita. "The applicable Laws of Commonwealth of Puerto Rico to this Public Hearing are the following: 1-Act No. 128 of June 29, 1977 Section 1. Public Policy on Energy of Puerto Rico. The Commonwealth's Public Policy on Energy shall be based on the following basic principals, among others. B- To obtain the lowest possible energy cost for our society. F- to adopt a Puerto Rico Energy Conservation Plan. This plan shall be established pursuant to applicable federal regulations. That is PURPA. G- To promote, in coordination with the agencies mentioned in section 9 scientific studies to provide Puerto Rico with alternate energy sources, which will contribute substantially to our economic growth by helping us to obtain a greater degree of self-sufficiency in energy matters. Special attention shall be given to solar energy and its associated sources, among others." Eso es "renewable energy resources, win, water, ...[unintelligible]. Not alternate energy sources like natural gas code, okay. That is definition of our energy policy by law. Second

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law. Puerto Rico Electric Power Authority Act Number 83 of May 2, 1941, 22 L.P.R.A., Section 196 Powers of the Authority." Es bueno mencionar un punto cuando ustedes ven las citas... Let me go back. It's important to notice that the Authority accommodates its ...[unintelligible]... powers in its laws in the organic... [unintelligible]. It doesn't mention what the law says. This is what the laws says. The Authority is created for the purpose of conserving, developing, and utilizing, and aiding in the conservation, development, and utilization of water and energy resources of Puerto Rico. Where is the natural gas, where is the code?. The Authority is created for the purpose of conserving, developing, and utilizing, and aiding in the conservation, development, and utilization of water and energy resources of Puerto Rico. C-To prescribe, adopt, amend and repeal bylaws and regulations governing the manner in which its general business may conducted. The bylaws so adopted shall have force of law once the provisions of sections 1041 to 1059 of title three are complied with. That is Puerto Rico Law Number 170, Uniform Procedure Act of August 12, 1988. This

proceedings are all the proceedings of power company in rate setting and discussing energy matters violates the ...[unintelligible]. We simply come here and just talk. It's a performance hearing. That's a violation. And this proceedings are according to State law and putting down the State laws which this public hearing is a violation of. 3-Puerto Rico Law Number 170, 'ta, ta, ta'. Whenever the agency proposes to adopt, amend or repeal a rule or regulation it shall publish a notice in a newspaper of general circulation in Puerto Rico. The notice shall contain a summary or brief explanation of the purpose of the proposed action. A reference of the legal provision that authorizes such actions and where the complete text of the regulations to be adopted will be available to the public. A rule regulation approved after the effective date of this act shall be null if it does not substantially meet with the provisions of this chapter. This Public Hearings are null. Fourth law- Governing Board of PREPA Resolution 1756, April 23, 1981. Exhibit 6." Por cuanto, la ley federal PURPA Public Law 95617 de 1978 establece que las compañías de electricidad deben

implantar programas de conservación de energía a través de la promoción de proyectos de cogeneración y de producción de electricidad en pequeña escala. Producción de electricidad en pequeña escala son aquellos que se hacen con medios renovables, puro renovables. Asuntos que reglamenta la Comisión Federal Reguladora de Energía, FERC, en adelante la orden 69.

OFICIAL EXAMINADOR:

Señor Arana, si me permite. Su línea...

SR. HÉCTOR ARANA:

Unjú.

OFICIAL EXAMINADOR:

...básicamente atacando el procedimiento.

SR. HÉCTOR ARANA:

Right.

OFICIAL EXAMINADOR:

Y éste no es el foro para atacar los procedimientos.

SR. HÉCTOR ARANA:

Good, good.

OFICIAL EXAMINADOR:

Okay. Nosotros...

SR. HÉCTOR ARANA:

We will define in the court, we will define in the

000201

court, okay. We will let, we will let the Federal Court be the judge of that, okay.

OFICIAL EXAMINADOR:

Por eso.

SR. HÉCTOR ARANA:

You are assuming a position, we assuming another position. So you take whatever ruling, what you want to do. It doesn't matter.

OFICIAL EXAMINADOR:

Yo, yo...

SR. HÉCTOR ARANA:

It is going to be questioned in court.

OFICIAL EXAMINADOR:

Perfecto.

SR. HÉCTOR ARANA:

You see. If your point is right or our point is right.

OFICIAL EXAMINADOR:

Perfecto. Yo le recuerdo a usted que yo soy Oficial Examinador de una Vista Administrativa.

SR. HÉCTOR ARANA:

Are you a lawyer?

OFICIAL EXAMINADOR:

Yo soy un abogado.

000202

SR. HÉCTOR ARANA:

Good.

OFICIAL EXAMINADOR:

Pero en este...

SR. HÉCTOR ARANA:

Refiérase, refiérase a los exhibits de la ley. Si usted es abogado, yo no soy abogado, a ver si yo estoy diciendo algo que no está específicamente relacionado a estas vistas públicas, cual lo que entiendo que usted está sugiriendo, que está sugiriendo que yo no estoy al tono con el "subjet matter" de esta Vistas Públicas.

OFICIAL EXAMINADOR:

Yo no le estoy sugiriendo.

SR. HÉCTOR ARANA:

Y me va a declarar en el informe, porque lo han hecho siempre, me van a declarar que mis comentarios no son pertinentes porque ha sido la práctica y costumbre de la Autoridad de Energía Eléctrica en todas las vistas públicas que yo he comparecido desde el 1982 utilizar eso. Pero sí estoy advertido. ¿Cuál es la advertencia que usted me quiere hacer?

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C00203

OFICIAL EXAMINADOR:

No, no es ninguna advertencia. Es sencillamente lo siguiente.

SR. HÉCTOR ARANA:

Unjú.

OFICIAL EXAMINADOR:

Yo soy el Oficial Examinador de una Vista Administrativa...

SR. HÉCTOR ARANA:

Good. And you are a lawyer.

OFICIAL EXAMINADOR:

...notificada...

SR. HÉCTOR ARANA:

Unjú.

OFICIAL EXAMINADOR:

...a través de unos periódicos de circulación general...

SR. HÉCTOR ARANA:

Sure.

OFICIAL EXAMINADOR:

...en cumplimiento con las...

SR. HÉCTOR ARANA:

I recognized that.

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OFICIAL EXAMINADOR:
...disposiciones de ley del procedimiento administrativo. Esta vista fue citada para evaluar la viabilidad de la adopción por parte de la Autoridad de Energía Eléctrica de las secciones 1252 y 1254.
SR. HÉCTOR ARANA:
Unjú. I agree.
OFICIAL EXAMINADOR:
Muy respetuosamente le pido que su ponencia se limite a establecer la posición suya con relación a estas disposiciones.
SR. HÉCTOR ARANA:
Sure.
OFICIAL EXAMINADOR:
Aclarando para el récord que yo soy un Oficial Examinador de criterio independiente. Nosotros estamos aquí con mi Asesor Técnico, el ingeniero Alfredo Huertas,...
SR. HÉCTOR ARANA:
Unjú.
OFICIAL EXAMINADOR:
...para recibir la prueba, que es la posición de ustedes, con relación al informe previamente

C00205

notificado y del cual usted al principio de su ponencia estableció que sí lo leyó. ¿Cuál es su posición con relación a ese informe? Para nosotros evaluar la posición de todos los deponentes porque si yo... Yo sí creo...

SR. HÉCTOR ARANA:

Unjú.

OFICIAL EXAMINADOR:

...en que si en estas Vistas Públicas hay información que me ayude a mí y a mi Asesor Técnico a establecer una posición contraria a la de la Autoridad de Energía Eléctrica, así se hará. Usted puede estar claro porque mi reputación en el ámbito profesional así siempre ha quedado establecida. Y yo le recuerdo una vez más, desconozco cuál ha sido su experiencia en los foros administrativos en la Autoridad de Energía Eléctrica, pero yo a usted le aseguro que el resultado de estas vistas se va a basar en el expediente administrativo y es un criterio independiente que es el que siempre me ha caracterizado. Con esto en mente y para récord nuevamente le pido que, por favor, se limite a lo que fue citado esta vista, secciones 1252 y 1254. Y se lo voy a agradecer de todo corazón que, por

favor, siga mi recomendación.

SR. HÉCTOR ARANA:

Sí, cómo no. Cuestión de orientación. En el aspecto de derecho sustantivo y procesal de estas vistas públicas, ¿cuáles son las reglas que aplican a este procedimiento?

OFICIAL EXAMINADOR:

Las reglas de los procedimientos administrativos típicamente son unas reglas flexibles. Las Reglas de Evidencia se pueden adoptar siempre y cuando el Oficial Administrador las adopte. Sin embargo, lo estricto de las Reglas de Evidencia no ha sido tocado en este foro; por lo tanto, como Oficial Examinador, y nadie lo había preguntado antes, pero se aclara, que son unas reglas flexibles. Reglas flexibles establece que yo puedo establecer mi criterio para permitir prueba que en otros foros más estrictos, como los Tribunales de Justicia, no serían admitidas.

SR. HÉCTOR ARANA:

Okay. ¿Hay oportunidad de interrogar la posición de la Autoridad? ¿Hay oportunidad de tener la documentación con la misma Autoridad de Energía Eléctrica utilizó y forma parte del expediente en

C00207

ese proceso administrativo relajado para simplemente dar una pizca de razonabilidad, "reasonableness" en estos procedimientos que son altamente complejos, según técnicos? Perdóneme.

OFICIAL EXAMINADOR:

Es que me ha hecho dos preguntas. Por favor, déjeme contestarlas porque después me puedo perder.

SR. HÉCTOR ARANA:

Cómo no.

OFICIAL EXAMINADOR:

Con relación a su primera pregunta, la ley establece, la ley y...

SR. HÉCTOR ARANA:

¿Cuál ley?

OFICIAL EXAMINADOR:

La Ley PURPA establece que estos procedimientos pueden ser de carácter legislativos y pueden ser de carácter para interrogar.

SR. HÉCTOR ARANA:

¿Y el State law? PURPA dice, los procedimientos son de acuerdo al State law.

OFICIAL EXAMINADOR:

Éstas son unas vistas...

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000208

SR. HÉCTOR ARANA:

¿Cuáles son los State laws?

OFICIAL EXAMINADOR:

Éstas básicamente son unas vistas de carácter legislativo, en el cual se establece la premisa fundamental por parte de la Autoridad en un informe y ustedes vienen aquí a tratar de poner o establecer su reacción a esa disposición al Oficial Examinador con prueba y con su informe y con su ponencia, de manera tal que el Oficial Examinador tenga aquella prueba pertinente que consta en el expediente para poder llegar a una determinación independiente, fundamentada en derecho y con los hechos y las conclusiones de derecho que entienda pertinente.

SR. HÉCTOR ARANA:

Cómo no, es cuestión de aclaración. Este...

OFICIAL EXAMINADOR:

Con relación a la segunda pregunta... Ya me perdí. ¿La segunda pregunta cuál era? Usted hizo...

SR. HÉCTOR ARANA:

It doesn't matter; it doesn't matter.

OFICIAL EXAMINADOR:

Yo creo que debe importar porque por alguna razón

000210

Autoridad de Energía Eléctrica y le incluí copia de la misma. Y estamos hablando de, de, de, de las reglas...

OFICIAL EXAMINADOR:

Por eso. Estamos...

SR. HÉCTOR ARANA:

...de llevar a cabo este procedimiento.

OFICIAL EXAMINADOR:

Tomamos cono...

SR. HÉCTOR ARANA:

Y entonces, ahí le estoy excluyendo, y refiérase al Exhibit 4, que dice la sección 196 los poderes de la Autoridad de Energía Eléctrica que puede enmendar y hacer lo que le dé la gana, siempre y cuando cumpla con la Ley 170 del Procedimiento Administrativo Uniforme. Eso es conforme a su Ley Orgánica.

OFICIAL EXAMINADOR:

Tomamos conocimiento. Yo, por mi parte, tomo conocimiento de las leyes aplicables a los procedimientos y a las leyes que no son aplicable.

SR. HÉCTOR ARANA:

Pues no se están aplicando aquí porque no se puede preguntar nada y no se puede tener información

C00211

tampoco.

OFICIAL EXAMINADOR:

Ah, ésa era su segunda pregunta. Si tiene... si puede tener información. Pues básicamente el informe es la información que está disponible, como usted leyó también en su ponencia a los otros ponentes. Ese informe usted, al inicio de su ponencia también estableció que lo había podido leer.

SR. HÉCTOR ARANA:

Unjú.

OFICIAL EXAMINADOR:

Eso es básicamente lo que está disponible para todos y es el inicio o de lo que en esta vista se va a estar ejecutando, que es básicamente las reacciones a ese informe. Yo sí vi como parte de su Anejo A que usted hizo una solicitud, Anejo 1, a la Autoridad de Energía Eléctrica, que creo que también lo dijo en su ponencia, lo hizo ayer.

SR. HÉCTOR ARANA:

Unjú.

OFICIAL EXAMINADOR:

La Vista es hoy 10; lo hizo ayer. Yo... me parece que dentro de lo que sería razonable, pues, yo creo

000212

que es... No es razonable que de un día para otro quizás le puedan contestar esa solicitud de documentación. El aviso, yo... me parece a mí, no recuerdo de memoria, pero me parece que este aviso de vista se hizo según dijimos en las afidávits originales, creo que el 22, 23... 21, 22 y 23 de junio; hace ya siete, casi veinte días. Y la solicitud suya se hizo ayer. Me parece que si este procedimiento, esto es una opinión muy personal no fundamentada en nada, sino la opinión personal...

SR. HÉCTOR ARANA:

No, la persona me va a proveer la información y entonces, entiendo yo, a menos que usted haga un "ruling" especial porque concluidas las vistas públicas hay un tiempo, cinco, diez días de someter información adicional o a menos que usted haga...

OFICIAL EXAMINADOR:

No, no, yo no voy cambiar...

SR. HÉCTOR ARANA:

...reglas nuevas de la ponencia.

OFICIAL EXAMINADOR:

Además de eso, nosotros vamos a tener... Va a estar el informe del Oficial Examinador, que se va a someter a la evaluación de la Junta de Gobierno.

000213

La Junta de Gobierno va a notificar la decisión final y la notificación final de la Junta de Gobierno usted puede apelarla o pedir una reconsideración.

SR. HÉCTOR ARANA:

Una reconsideración. Inclusive, cuando la radique en el Departamento de Estado puede ser "challenged" también.

OFICIAL EXAMINADOR:

Perfecto. Esto es nuestro sistema democrático.

SR. HÉCTOR ARANA:

Okay. Fíjese...

OFICIAL EXAMINADOR:

Gracias a Dios que contamos con él.

SR. HÉCTOR ARANA:

Cosa que la Autoridad de Energía Eléctrica ha violado por 25 años, pero eso es otra cuestión. Fíjese, basándonos en lo razonable, en lo razonable, dos vistas públicas de 10:00 a 2:00, cuatro horas, el tema altamente técnico, complejo. Y, eso sí, le doy las gracias porque es la primera vez que en una vista pública que yo me he podido extender más de quince minutos porque normalmente quince minutos, "pun". Que "reasonableness,

C00214

reasonableness on this procedure". Okay. Vamos a terminar, ya estoy casi por concluir. Ahí están las tres resoluciones de la Junta de Gobierno de la Autoridad relacionada a los estándares, una en el '81, una en el '83 y una del '99. Y por concluir, "In contrast with the above laws and resolutions of the Governing Board of PREPA, regarding interconnection standards, it becomes clear that the actions taken by the PREPA do not permit the interconnection of renewable energy sources to its power generation distribution system and the conduct of this Public Hearing are Ultra Vires and outside of reasonableness. Chrysler Corporation versus Brown, 41...", "pan, pan, pan" y hay un montón de jurisprudencia del Tribunal Supremo ahí de los casos. "The subject matter of the hearing is highly technical and complex to be properly discussed in two hearings lasting only four hours each and the participants be only provided fifteen minutes to present their views regarding the matters without having the opportunity to ask questions and receive answers from PREPA. The Authority appointed multidisciplinary working committees to study the aspects to be evaluated

C00215

mentioned on page one in paragraph two. The Authority has not provided such documented information to the electric consumers and to the participants of this hearing. The Authority has not provided documented information to the electric consumers to the participants of these hearings regarding the recommendations, as to any necessary advisable revisions of rates and charges, that Washington Group International, Consulting Engineers of PREPA, for over 50 or 60 years, has provided to the Authority regarding the subject matter of these Public Hearing under the provision of Section 706 of Article VII of the Trust Indenture Agreement, dated as of January 1, 1974, as amended and supplemented between the Authority and U.S. Bank Trust National Association, the successor Trustee for the 1974 Trust Agreement. Upon review of the information, cost of generation cents per kwh, provided by PREPA, on page 16 of the document. Consideration of time based metering and communications interconnection standards for distributes resources, the subject matter of this Public Hearing, I find such information to be nonfactual, in contrast with documented information

CC0216

provided in Annual Reports prepared by Washington Group International, Consulting Engineers of PREPA, during the past decade. I have, since July 1, 2003, following exactly PREPA interconnection regulations tried to obtain a permit to install a small residential wind turbine battery charging system. Exhibit 9, copy of letter dated July 1, 2003 from Mr. Hector Arana to Miss Yolanda Ramos. At this moment..." Está por aquí presente, tremenda persona, una buena atención, diligente, pero después que salió el proyecto de las manos de ella, paralizado. Este... "At this moment PREPA continues to obstruct permitting the installation of the small wind turbine system installation. Exhibit 10, copy of letter dated April 20, 2007 from Mrs. Yoamarie Figueroa to Mr. Hector Arana". La señora Yoamarie Figueroa es la Asistente Ejecutivo del ingeniero Alicea Flores que va a deponer, que está a cargo de esa División...

OFICIAL EXAMINADOR:

Para...

SR. HÉCTOR ARANA:

Y está "paralizao" el proyecto. Está allí, está en el Exhibit, en el Exhibit, en el Exhibit 20.

C00217

OFICIAL EXAMINADOR:

Sí, perdone que lo interrumpa. Lo que pasa es que por segunda vez dice que el ingeniero Alicea va a deponer y el ingeniero Alicea ya lo hizo.

SR. HÉCTOR ARANA:

Oh, lo hizo, oh, good. It doesn't matter. Este... "In the late afternoon of July 9, 2007 I received a fax from Mrs. Sonia Miranda Vega, PREPA Official, regarding my request of being provided copy of documented information pertinent to this Public Hearing. Exhibit 11, copy of fax letter from Mrs. Sonia Miranda Vega to Mr. Hector Arana. I will procure the documented information regarding the EPRI document and other information pertinent to these public hearings during the next ten days . I have planned to present additional written comments to PREPA regarding the subject matter of these hearings withing the time frame of July 15 and July 27, 2007. Thank you very much for allowing me to participate as intervener in this Public Hearing. I am prepare to answer any questions that the Examiner has. Hector Arana. Submitted."

OFICIAL EXAMINADOR:

Muchas gracias, señor Arana por su ponencia.

000218

Ingeniero Alfredo Huertas, ¿tiene alguna pregunta para el señor Arana?

ASESOR TÉCNICO:

No.

OFICIAL EXAMINADOR:

Tampoco tengo preguntas para el señor Arana. Nuevamente le doy las gracias por su participación en este procedimiento.

SR. HÉCTOR ARANA:

Permiso para retirarme.

OFICIAL EXAMINADOR:

Cómo no.

SR. HÉCTOR ARANA:

Thank you.

OFICIAL EXAMINADOR:

Estas Vistas fueron citadas de 10:00 a 2:00 de la tarde. Es la una menos quince. Estaremos aquí hasta las 2:00 esperando cualquier otra persona que así llegue para poder entonces atenderlo hasta las 2:00 de la tarde. A las 2:00 daremos por terminados los trabajos. Las personas que quieran continuar en sala lo pueden hacer. Nosotros tenemos la obligación, no, de permanecer hasta las 2:00 de la tarde.

000219

ING. GERARDO COSME NÚÑEZ:

Tengo una pregunta. Se podría, ya que no hay más deponentes de momento, ¿se podría tener la discreción del Oficial Examinador de abrir la Vista Pública que sea una vista... creo que el término es consultivo, que uno puede hacer preguntas a la misma Autoridad de Energía Eléctrica y hacerla más informal, ya que las presentaciones han sido expuestas y tenemos el tiempo disponible?

OFICIAL EXAMINADOR:

Número uno, aclarandose, la notificación establece que estas vistas van a celebrarse de 10:00 de la mañana a 2:00 de la tarde. Por lo tanto, hasta las 2:00 de la tarde yo no puedo tomar ninguna decisión distinta a eso, salvaguardando el derecho de cualquier persona que dada esa notificación decida llegar al lugar a la una y media, una y cuarenticinco, dos menos cinco. Por otro lado, su petición de tornar la vista una informal de manera que se puedan contestar cosas, por lo menos desde mi posición como Oficial Examinador yo no he aquilatado la prueba. Yo no podría en este momento contestar ninguna pregunta porque estaría faltando lo que sería una respuesta educada en el

CC0220

expediente.

ING. GERARDO COSME NÚÑEZ:

La pregunta sería más bien lo que es la relación cliente y la Autoridad de Energía Eléctrica. Usted como Oficial Admini...

OFICIAL EXAMINADOR:

Examinador.

ING. GERARDO COSME NÚÑEZ:

...Examinador estaría en la posición de ver eso. Pero, este... podríamos estar, ya que la Autoridad de Energía Eléctrica realmente depuso, es prácticamente... La Vista la "seteó", la informó, la organizó la Autoridad de Energía Eléctrica y la Autoridad de Energía Eléctrica también fue deponente, que entiendo que quizás pueda ser una discusión entre ambas partes, ambos deponentes, con la Autoridad de Energía Eléctrica. Eso en la Legislatura se hace y se ha hecho. Como habían informado de que ésta es una vista de forma Legislativa, pues, entiendo la pregunta, pero es a discreción suya.

OFICIAL EXAMINADOR:

Lo que pasa es que yo creo que a su petición yo no tengo ningún tipo de poder decisional con relación

C00221

a si la Autoridad está dispuesta a hacer un aparte y contestar sus preguntas relacionadas al tema. De verdad que yo en ese sentido no tengo ningún poder discrecional. No puedo decir ni sí ni no. Yo les recuerdo... Fuera de récord.

--FUERA DE RÉCORD--

OFICIAL EXAMINADOR:

Buenas tardes. Son las 2:00 de la tarde de hoy 10 de julio del 2007. Dado que no hay más deponentes en la vista de hoy, damos por terminados los trabajos de este proceso que comenzó ayer y termina hoy como parte del vivo proceso de ley de las vistas evidenciarias para determinar la viabilidad de la adopción por parte de la Autoridad de Energía Eléctrica de las secciones 1252 y 1254 del EPACT 2005. Gracias a todos por su asistencia, hasta luego.

FINALIZAN LOS PROCEDIMIENTOS A LAS 2:00 P.M.

000222

CERTIFICACIÓN DE TAQUÍGRAFA DE RÉCORD

Yo, Maribel Rivera Sánchez, taquígrafa de récord, certifico:

Que la que antecede es una transcripción fiel y exacta del testimonio prestado y el procedimiento llevado a cabo ante mí en la Vista Pública sobre los Estándares del EPAct2005 - Time Based Metering and Communications e Interconnection Standards for Distributed Resources, la cual se llevó a cabo en Santurce, Puerto Rico, el día 10 de julio de 2007.

Que en esta misma fecha estoy remitiendo el original y dos copias de dicha transcripción a la ingeniero Sonia Miranda Vega a su dirección en la Autoridad de Energía Eléctrica en Santurce, Puerto Rico.

Y para que así conste, firmo la presente en Toa Alta de Puerto Rico, a 13 de julio de 2007.

Maribel Rivera Sánchez

TAQUÍGRAFA DE RÉCORD

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000224

Apéndice C

C00226

PONENCIA DE LA AEE SOBRE LOS ESTÁNDARES DEL EPAct 2005 – *TIME-BASED METERING AND COMMUNICATIONS* E *INTERCONNECTION STANDARDS FOR DISTRIBUTED RESOURCES*
Vistas Públicas 9 y 10 de julio de 2007

Buenos días. Mi nombre es Juan F. Alicea Flores, soy ingeniero, Director de Planificación y Protección Ambiental y comparezco a estas vistas públicas en representación del Ing. Jorge A. Rodríguez Ruiz, Director Ejecutivo de la Autoridad de Energía Eléctrica de Puerto Rico. Comparecemos para presentar la posición de la Autoridad con relación a dos de los estándares establecidos en el *Energy Policy Act* del 2005 **(EPACT05)** el cual enmendó la ley federal *Public Utility Regulatory Policies Act*, mejor conocida como PURPA. Estos estándares son *Time-Based Metering and Communications* e *Interconnection Standards for Distributed Resources*.

Es relevante expresar, que nuestra ponencia está fundamentada en el informe "Consideración de los Estándares del EPACT 2005: *Time-Based Metering and Communications – Interconnection Standards for Distributed Resources*" que estuvo disponible a todo el público en las oficinas comerciales, que fueron informadas en el Aviso de estas vistas públicas que publicamos en varios periódicos de circulación general de Puerto Rico. Así también está disponible en una dirección de Internet que informamos en dicho aviso.

La Autoridad debe determinar si implementa los estándares en Puerto Rico, para lograr los propósitos de PURPA. Éstos son: promover la conservación de la energía que proveen las compañías de electricidad, optimizar la eficiencia en el uso de instalaciones y recursos de las compañías de electricidad, y establecer tarifas equitativas para los consumidores de electricidad.

000227

La Autoridad tomará su determinación respecto a la adopción de estos estándares conforme a la información que se presente en estas vistas y las recomendaciones del Oficial Examinador.

000228

PURPA Sec. 1252 - *Time-Based Metering And Communications*

En primer lugar explicaremos el estándar *Time-Based Metering and Communications.* El propósito de este estándar es proveer a todas las clases de clientes y a clientes individuales según soliciten, tarifas cuyos cargos varíen durante los diferentes periodos de tiempo y reflejen la diferencia, si alguna, en los costos en que incurre la compañía de electricidad en generar y comprar energía. El EPACT05 menciona ejemplos de cuatro tipos de estas tarifas, éstas son: Tiempo de Uso (TOU), *Critical Peak Pricing* (CPP), *Real Time Pricing* (RTP) y créditos para clientes con carga.

Las tarifas en las cuales los precios varían dependiendo del periodo en que el cliente usa la energía, tienen como propósito proveer señales de precio para que éstos decidan cuándo consumir la electricidad. Esto podría resultar en reducciones en la demanda en horas en las cuales producir la energía es más costoso y de esta manera, también aumenta la confiabilidad del sistema. Además, esto podría reducir la necesidad de añadir al sistema de generación unidades que se utilizan en periodos de demanda alta, tales como las turbinas de gas.

Según PURPA, las tarifas basadas en tiempo deben ser costo efectivas, esto significa que los beneficios que recibe a largo plazo tanto la compañía de electricidad como los clientes exceden los costos asociados con la implementación de estas tarifas.

Esto hace necesario que al considerar adoptar este estándar, se evalúen los costos en que tendría que incurrir la compañía de electricidad. Algunos de éstos son: inversión en medidores y otra

C00229

infraestructura para recopilar los datos, costos administrativos, adiestramiento técnico a los empleados para analizar la información y cambios en programación para facturar a los clientes. Los costos relacionados con el procesamiento de datos pueden aumentar debido al volumen de información. También, se deben considerar los costos administrativos para implementar y promocionar la tarifa basada en tiempo y educar a los clientes.

Los medidores tradicionales no tienen la capacidad requerida para que las compañías de electricidad implementen tarifas basadas en tiempo. Los medidores inteligentes pueden registrar y almacenar el consumo de energía del cliente por periodo de tiempo. Con esta información se puede facturar a clientes con tarifas basadas en tiempo. Por lo tanto, la compañía de electricidad tendría que incurrir en costos para la adquisición e instalación de medidores nuevos. Estos costos dependen de la tecnología del metro, de la cantidad de medidores a adquirir y del tipo de tarifa basada en tiempo que se adopte.

La Autoridad está en el proceso de completar la instalación de medidores de lectura remota por medio de TWACS (*Two Way Automatic Communication System*) para todos los servicios a distribución secundaria. Los medidores de TWACS no poseen memoria para almacenar la información de consumo y demanda por periodo de tiempo. Por lo tanto, la Autoridad no tiene medidores capaces de agrupar el consumo del cliente por periodo de tiempo para los servicios a voltaje de distribución secundaria. Sin embargo, existen en el mercado medidores con esta capacidad, pero son más costosos que los medidores utilizados actualmente.

Cabe señalar que, en la mayoría de las ocasiones, los clientes deben alterar su patrón de consumo

para beneficiarse de las tarifas basadas en tiempo. La acogida de estas tarifas depende grandemente de que los ahorros que obtiene el cliente excedan los costos e inconvenientes en que tienen que incurrir para cambiar su patrón de consumo. La Autoridad tiene disponible tarifas tiempo de uso para las clases de servicio comercial e industrial en su estructura tarifaria. Esto debido a que los clientes comerciales e industriales tienen más oportunidad de transferir parte de su carga y modificar su patrón de consumo.

En nuestro análisis graficamos la curva de demanda para definir cuáles serían los periodos de tiempo pico y fuera de pico de nuestro sistema actual. La gráfica de la demanda total del sistema muestra que no hay variaciones significativas en la demanda en un período de 24 horas. Además, analizamos qué porción de la generación se suple con unidades base y de unidades pico. De este análisis surge que la demanda de lunes a viernes entre las 12:00 a.m. y las 9:00 a.m. se suple con unidades base, por lo que este periodo se puede clasificar fuera de pico. El resto del tiempo en los días de semana es periodo pico, el cual se suple con unidades base y unidades pico. Los fines de semana se pueden clasificar como periodo fuera de pico, con excepción de las 7:00 p.m. a las 12:00 a.m. También estudiamos el comportamiento de la clase residencial y cómo éste afecta la curva de demanda del sistema. En el análisis determinamos que la demanda máxima de los clientes residenciales ocurre dentro del periodo pico del sistema de la Autoridad, aproximadamente de 7:00 p.m. a 12:00 a.m. Al igual que en la curva del sistema, en los fines de semana se observa un aumento en la demanda desde las 7:00 p.m. hasta las 12:00 a.m.

Utilizamos modelos matemáticos para calcular el precio promedio de la generación total para los

periodos pico y fuera de pico del año 2009. Los resultados del análisis indican que la diferencia en costo entre los periodos es mucho menor de 1¢/kWh (fluctúa entre 0.15 y 0.47 ¢/kWh). La razón principal que propicia que esta diferencia no sea significativa es la mejora en la eficiencia de las unidades pico, lo cual reduce sus costos de producción. Algunas de éstas son: la conversión de Cambalache a un Ciclo Combinado, el aumento en capacidad y eficiencia de las turbinas de gas de Mayagüez, la adición al sistema del Ciclo Combinado de San Juan (*Repowering*) y el uso de gas natural en el Ciclo Combinado de Aguirre.

Como resultado de esta evaluación la Autoridad entiende que no debe adoptar el estándar *Time-Based Metering and Communications* para la clase residencial. La razón principal para que la Autoridad no adopte este estándar para los clientes residenciales es que de acuerdo con el comportamiento típico de la clase residencial y la corta duración del periodo fuera de pico, entendemos que a los clientes residenciales les resultaría poco práctico y difícil transferir la carga. Si el cliente no puede transferir carga, la tarifa podría resultarle más costosa que una tarifa basada en costo promedio. Además, la demanda del sistema no tiene fluctuaciones considerables con respecto a la demanda máxima durante el periodo de 24 horas en cualquier día del año. Por lo tanto, el transferir carga podría causar un pico de demanda en el periodo fuera de pico.

Otra razón para no adoptar este estándar es que la diferencia en costos de generación entre los periodos pico y fuera de pico no justifica la transferencia de demanda de un periodo a otro. Además, la necesidad de reemplazar el equipo de medición actual y modificar el sistema de facturación resultaría en un aumento en costos que revierten al cliente.

C00232

Varias compañías de electricidad en los Estados Unidos también recomendaron no adoptar este estándar para la clase residencial. Estudios indican que algunas compañías tienen disponibles tarifas basadas en tiempo para clientes residenciales, pero éstas no tienen mucha acogida.

La Autoridad continuamente realiza estudios para evaluar posibles alternativas tarifarias y podría considerar la viabilidad de este tipo de tarifa para los clientes residenciales en el futuro.

PURPA Sec. 1254 - *Interconnection Standards For Distributed Resources*

El segundo estándar que discutiremos es el de interconexión del EPACT05. El mismo establece que la compañía de electricidad deberá ofrecer servicios de interconexión a generadores, localizados en los predios de los clientes, al sistema de distribución eléctrica. Éste indica que estos servicios estarán basados en el estándar IEEE 1547 del *Institute of Electrical and Electronics Engineers*. Además, los acuerdos y procedimientos que se establecerán deberán incorporar las mejores prácticas actuales de interconexión, incluyendo las prácticas adoptadas por los modelos de interconexión de las asociaciones de agencias reguladoras estatales. Estos deberán ser justos y razonables, y no discriminatorios o preferenciales.

Durante la última década el tema de interconexión de generadores al sistema de distribución cobró fuerza en las compañías de electricidad a nivel nacional. Esto se debe en parte al desarrollo de las tecnologías de generación y protección utilizadas. Además, el desarrollo de estándares de interconexión por parte de varios estados pioneros, así como la redacción de

C00233

modelos de interconexión por parte de entidades reguladoras, contribuyeron al crecimiento de los estándares de interconexión en los Estados Unidos. Recientemente, el EPACT05, con su estándar de interconexión, aumentó la exposición del tema de interconexión a nivel nacional, al requerir a las compañías de electricidad considerar la adopción del mismo.

Entre los estados pioneros en el tema de la interconexión están California, Nueva York y Texas. Estos tuvieron como meta desarrollar estándares de interconexión que establecieran una metodología uniforme para permitir la interconexión de sistemas de generación de manera segura y confiable. A pesar de que estos estados realizaron procesos independientes para establecer sus estándares de interconexión, los resultados de los mismos fueron muy similares. De igual manera, entidades nacionales reguladoras desarrollaron modelos de interconexión que incorporan algunas de las prácticas incluidas en los estándares ya establecidos. A mayo de 2007, aproximadamente 24 de los estados han incorporado algún tipo de estándar de interconexión según el *Interstate Renewable Enenrgy Council* (IREC). Éstos estándares por lo general consideran los aspectos técnicos, administrativos y legales aplicables a la interconexión.

La Autoridad, al considerar la implementación de un estándar de interconexión, debe evaluar los requisitos técnicos, administrativos y legales. Los requisitos técnicos aseguran que la interconexión de los generadores no afectará adversamente la confiabilidad del sistema eléctrico, así como la seguridad tanto del sistema como de sus empleados y sus clientes. Los requisitos administrativos definen los procedimientos y trabajos necesarios para lograr la interconexión. Los requisitos legales establecen los términos contractuales del acuerdo de interconexión.

C00204

Como parte de la evaluación, la Autoridad examina los efectos de interconectar generadores a su sistema de distribución eléctrica. La configuración del sistema de distribución de la Autoridad es radial. Éste no está diseñado para incorporar fuentes de generación o almacenamiento de energía eléctrica externos. Por esto, la interconexión de generadores al sistema de distribución puede causar problemas de seguridad, confiabilidad y de operación en el sistema. Entre éstos se encuentran la formación de islas eléctricas, efectos adversos a los sistemas de protección, sobrevoltajes, fluctuaciones de voltajes, inyección de corriente harmónica, parpadeos (flicker) y resonancia. Todo estándar de interconexión tiene que tomar en cuenta los efectos adversos de interconectar generación para garantizar la seguridad y confiabilidad del sistema eléctrico.

El EPACT05 establece que los estándares de interconexión que adopten las compañías eléctricas deben estar basados en el estándar IEEE 1547. Éste provee una metodología uniforme para la interconexión de generadores, al establecer los requisitos técnicos mínimos para lograr una interconexión segura y confiable al sistema de distribución eléctrica. El mismo señala cómo los generadores operarán bajo condiciones normales y ante disturbios en el sistema de distribución. Además, incluye los requisitos y especificaciones de pruebas a los que se someterán estos equipos. El estándar no incluye todos los aspectos técnicos que deben evaluarse para su cumplimiento. Por ejemplo, el estándar no establece límites de contribución de corriente de corto circuito que garanticen que estos sistemas no afecten adversamente el funcionamiento de los equipos de protección. Tampoco considera la configuración de los transformadores de interconexión utilizados o los efectos de resonancia que pueden surgir bajo ciertas condiciones operacionales. Estos y otros aspectos técnicos deberán considerarse junto a aquellos establecidos en el estándar IEEE 1547 para garantizar la confiabilidad del sistema eléctrico, así como la

seguridad tanto del sistema como de sus empleados y sus clientes.

Además, los acuerdos y procedimientos que se establezcan en el estándar de interconexión deberán incorporar las mejores prácticas contemporáneas de interconexión. Éstas deben incluir aquellas adoptadas en los modelos establecidos por las asociaciones de agencias estatales reguladoras. Entre estos, se destaca el modelo de interconexión de la *National Association of Regulatory Utility Commissioners*, (NARUC), el cual incluye guías de los procesos de revisión técnicos y administrativos, y un modelo para el acuerdo de interconexión.

De igual manera, al evaluar un estándar de interconexión es necesario considerar los costos asociados al proceso de interconexión. Estos costos están relacionados a los trabajos necesarios para lograr la interconexión segura de estos equipos. Actualmente, las prácticas de interconexión adoptadas por los estados disponen que el cliente que solicita la interconexión es responsable de asumir ciertos costos asociados a la misma. Estos típicamente incluyen los costos de los estudios de ingeniería, trabajos en el campo y reemplazo de equipo o construcción de instalaciones eléctricas por parte de la compañía de electricidad para viabilizar la interconexión. Generalmente, las compañías informan a sus clientes el costo de realizar el trabajo, y el cliente determina si desea continuar con el proceso de interconexión.

Otro aspecto que considera la Autoridad al evaluar establecer este estándar es el impacto que el mismo puede ocasionar a su estabilidad financiera. Los clientes con generación propia suplirían parte de sus cargas eléctricas, por lo que comprarían menos energía a la Autoridad. A pesar de esto, la Autoridad tiene que mantener una capacidad adecuada en su sistema para suplir todas las

C00236

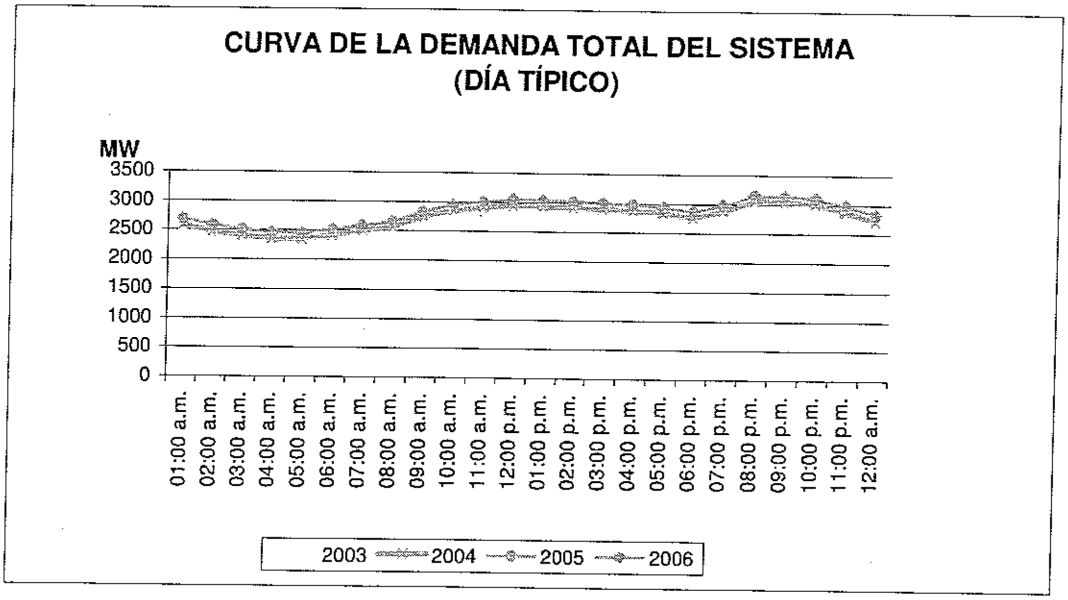
cargas de los clientes con generación distribuida cuando estos no generen.

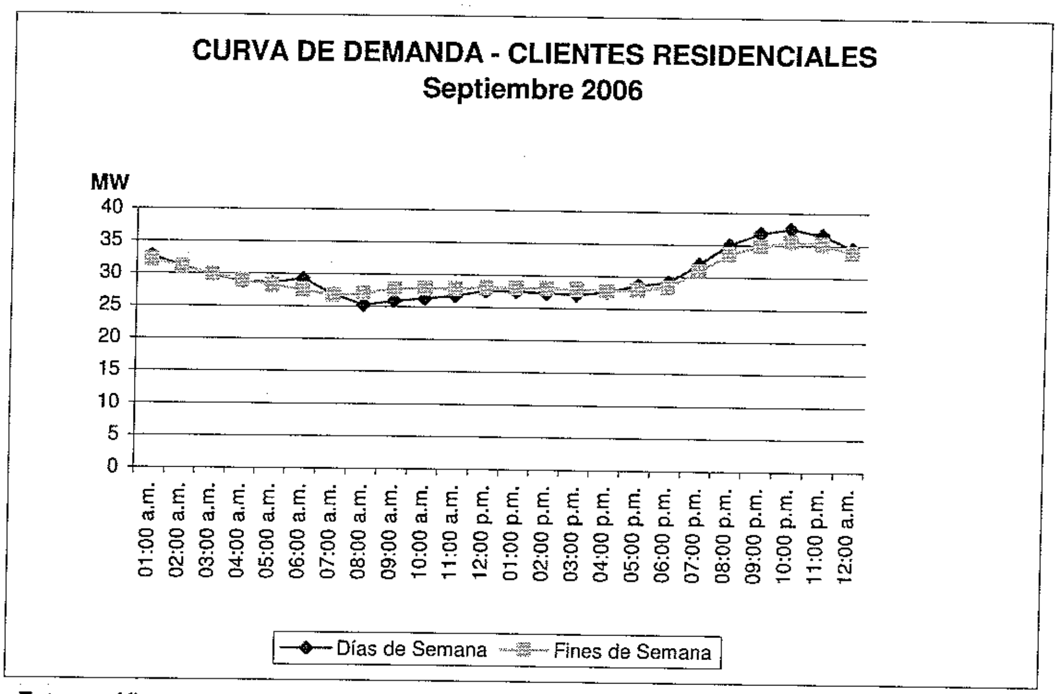
Por otra parte, la adopción de un estándar de interconexión ayudaría a fomentar el desarrollo de generación con fuentes de energía renovable. La disponibilidad de algunas fuentes de energía renovable, tales como el viento y el sol, es variable y depende de factores tales como las condiciones climáticas, la hora del día o la época del año. Al estar interconectados al sistema de la Autoridad, se reduce o elimina la necesidad de incorporar tecnologías de almacenamiento de energía (baterías) o generadores de resguardo, lo que reduce significativamente el costo de estos sistemas.

Como resultado de la evaluación realizada, la Autoridad entiende que debe adoptar el estándar de interconexión para generación distribuida que cumpla con lo establecido en el *Interconnection Standard For Distributed Resources* del EPACT05. El mismo debe considerar las particularidades del sistema eléctrico de la Autoridad y armonizar los procedimientos a sus procesos administrativos.

Con esta información concluimos nuestra ponencia. Muchas gracias.

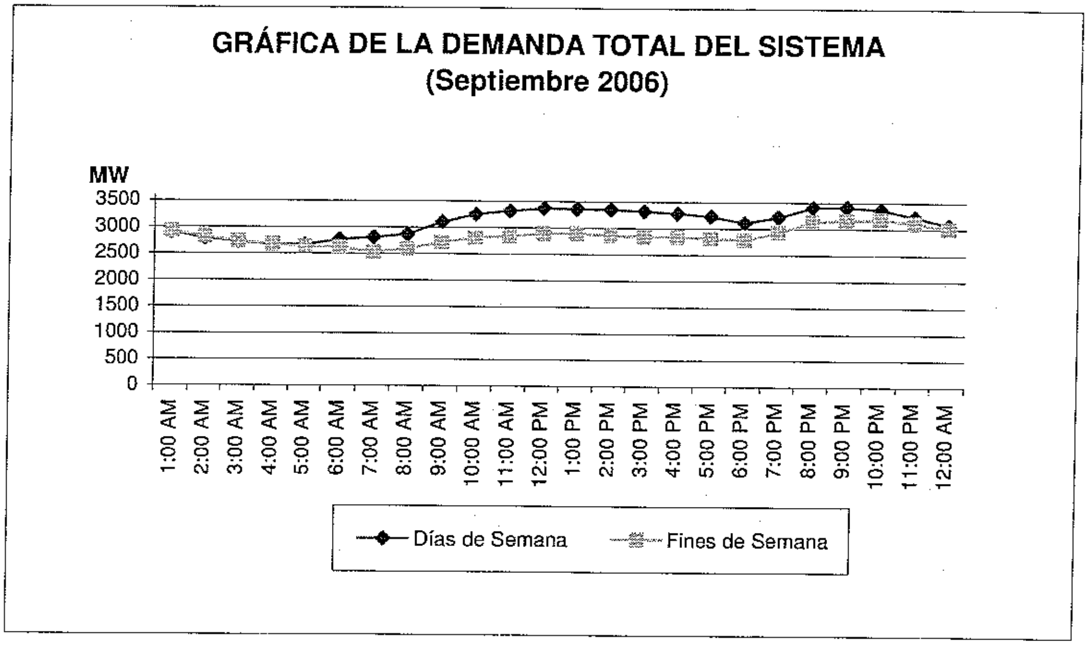
C00237





Esta gráfica presenta la totalización de clientes residenciales servidos con las subestaciones: SUB-3010 de Villa del Rey en Caguas, SUB-1206 de Encantada en Trujillo Alto y SUB-5016 de Villa del Carmen en Ponce.

000208



GRÁFICA DE LA DEMANDA TOTAL DEL SISTEMA
(Septiembre 2006)
MW
3500
3000
2500
2000
1500
1000
500
0
1:00 AM
2:00 AM
3:00 AM
4:00 AM
5:00 AM
6:00 AM
7:00 AM
8:00 AM
9:00 AM
10:00 AM
11:00 AM
12:00 PM
1:00 PM
2:00 PM
3:00 PM
4:00 PM
5:00 PM
6:00 PM
7:00 PM
8:00 PM
9:00 PM
10:00 PM
11:00 PM
12:00 AM
Días de Semana
Fines de Semana

000239

000240

9 de julio de 2007

Ponencia ante las vistas públicas de la Autoridad de Energía Eléctrica (AEE) para determinar si la AEE adopta o no los siguientes estándares contemplados en la Energy Policy Act (EPAct) 2005, Sección 1252 *Time-Based Metering and Communications* y *Sección 1254 Interconnection Standards for Distributed Resources.* Estos enmiendan parte de lo establecido en el Public Utility Regulatory Policies Act de 1978 (PURPA).

Salón de Actividades en La Guancha
Ave. Santiago de los Caballeros
Sector La Guancha, Ponce

Buenos días,

En una Isla como Puerto Rico, es importante que el Gobierno vele por el bien común, aquellas areas de nuestra vida como sociedad donde las condiciones económicas no necesariamente son la prioridad, sino el bienestar del pueblo. La confiabilidad de nuestro sistema eléctrico es parte del bien común, ya que el mismo es vital para nuestro desarrollo socio-económico, y no tenemos la posibilidad de interconexión con otros sistemas eléctricos como sucede por ejemplo en los 48 estados contiguos de EEUU. La protección del ambiente, y el velar por la justicia social, en especial en poblaciones vulnerables, es otro importante deber del gobierno en su responsabilidad de velar por el bien común. En todo debate o discusión sobre nuestro futuro energetico, en el caso que nos toca hoy, energía eléctrica, debe hacerse énfasis en que las alternativas a evaluar no pueden ser vistas únicamente, o dando mayor peso, a las dimensiones económicas que a los aspectos ambientales y sociales relacionados a tales alternativas. Hacer lo contrario prepara el camino para controversias, problemas futuros y consecuencias no-intencionadas que pudieron haber sido atendidos desde el inicio del proceso de evaluación dando mayor participación e información a todos los sectores afectados (positiva o negativamente).

Durante el siglo XX, la Autoridad de Fuentes Fluviales, luego convertida en la Autoridad de Energía Eléctrica, tuvo la importante tarea de construir, mantener y manejar la infraestructura electrica que permitió el desarrollo economico de la Isla. Para esa tarea, fue necesario adquirir y combinar todos los recursos de energía eléctrica en PR para lograr la costo-efectividad que permitía una estructura jerárquica de operación de sistemas de potencia. En la última década del siglo XX, los sistemas de potencia a nivel mundial experimentaron grandes cambios debido a adelantos tecnológicos, cambios en política pública, y preocupaciones ambientales y sociales en distintos países. Las compañías eléctricas se re-organizaron de acuerdo a estos factores, y a las realidades de cada país. Una

C00241

constante en muchos países ha sido un énfasis en servicio al cliente (por ejemplo, a través de programas vanguardistas de calidad de potencia), estrategias de reducción del uso de combustibles fósiles, y un repensar en la estructura clásica de generación, transmisión y distribución a través de estrategias como generación distribuida y mayor participación de los clientes en el manejo de sus tarifas eléctricas. Nos ha llegado el momento en Puerto Rico de revisar la manera en que hemos manejado y estamos manejando nuestro sistema de energía eléctrica, y tenemos la oportunidad de iniciar esta evaluacion de una manera que considere la totalidad y complejidad económica, ambiental y social del asunto.

La AEE ha declarado su intención, o inclinación, a adoptar el Standard de la *Sección 1254 Interconnection Standards for Distributed Resources* y a no adoptar el estándar de la Sección 1252 *Time-Based Metering and Communications.* Esta es la posición expresada en el documento "CONSIDERACIÓN DE LOS ESTÁNDARES DEL EPACT 2005: *TIME-BASED METERING AND COMMUNICATIONS INTERCONNECTION STANDARDS FOR DISTRIBUTED RESOURCES"* preparado por la División de Planificación y Estudios de la AEE con fecha junio de 2007. A continuación expresamos nuestra opinión sobre cada una de estas intenciones.

Sección 1254 Interconnection Standards for Distributed Resources

Aplaudimos la intención de la AEE a adoptar el Standard de la *Sección 1254 Interconnection Standards for Distributed Resources.* Menciona la AEE en su informe que el reglamento que finalmente se adopte debe cumplir "*con las normas, reglamentos y estándares aplicables, incluyendo el estándar IEEE 1547. ... Además, recomendamos que al diseñar los procedimientos y acuerdos de interconexión, la Autoridad considere los modelos establecidos en las guías de NARUC. No obstante, la Autoridad deberá armonizar los procedimientos establecidos en estas guías a sus procesos administrativos.*"

Es de suma importancia que al momento de producir el reglamento de interconexión el mismo describa un proceso ágil y sencillo de interconexión a la red eléctrica que permita al pequeño productor comenzar a producir energía en un periodo corto. Que el mismo cumpla con los estándares aceptables de interconexión sin inclusión de requisitos adicionales o especiales que encarezcan el sistema o su operación. En ese proceso es vital hacer una distinción entre generadores residenciales o comerciales de una capacidad pequeña (menos de 50 kW), y aquellos generadores de mayor capacidad aunque para efectos del sistema se consideren pequeños. La conexión de generadores residenciales debe fomentarse al máximo de manera que el pueblo tenga herramientas para asumir y manejar sus necesidades energéticas, en especial durante y después de eventos atmosféricos o problemas con el servicio eléctrico. Entendemos que la posible inversión económica en este proceso no debe recaer en su totalidad en la AEE, mas sin embargo la agencia debe convertirse en un ente facilitador de tales interconexiones a través de procesos administrativos y para obtención de permisos simple en casos donde el impacto en el sistema es prácticamente

000242

ninguno por ser generadores muy pequeños. El Gobierno, por otro lado, en su deber ministerial de velar por el bien común, debe establecer los incentivos económicos necesarios para que la ciudadanía tenga la posibilidad de adquirir e instalar estas tecnologías, como ha sucedido en otros países. Hacer lo contrario implicaría cargas adicionales al ciudadano promedio que impedirían su posibilidad de progreso social, y cerraría las puertas a alternativas ambientalmente mejores que la quema de combustibles fósiles.

Solicitamos la oportunidad de participar en la creación de este reglamento de interconexión. Sugerimos la creación de una estructura colaborativa, entre la AEE y la ciudadanía, para producir este reglamento y nos ponemos a la disposición del funcionario a cargo de esta tarea en la AEE para viabilizar esta colaboración. Nos interesa sobremanera la colaboración en la creación de este reglamento, en la definición de este proceso ágil y sencillo de interconexión a la red eléctrica que permita al pequeño productor comenzar a producir energía en un periodo corto, pues es el primer paso para que podamos en Puerto Rico iniciar una transición ordenada hacia recursos energeticos distintos a los combustibles fósiles.

Sección 1252 *Time-Based Metering and Communications*

En lo que respecta a la Sección 1252 *Time-Based Metering and Communications* la AEE se inclina por no adoptar este estándar. Sin embargo el análisis presentado en el documento "CONSIDERACIÓN DE LOS ESTÁNDARES DEL EPACT 2005: *TIME-BASED METERING AND COMMUNICATIONS INTERCONNECTION STANDARDS FOR DISTRIBUTED RESOURCES*" preparado por la División de Planificación y Estudios de la AEE para rechazar este estándar nos resulta un poco confuso y falto de los datos necesarios, en el documento o disponibles a través de la AEE, para estudiar las interioridades del análisis.

Son múltiples las ventajas de ofrecer medición, y facturación, basada en el intervalo de tiempo de consumo y creemos que el asunto amerita mayor consideración y posible adaptación para los clientes residenciales. A continuación presentamos algunas de estas ventajas.

En su informe titulado "Assessment of Demand Response and Advanced Metering" la Federal Energy Regulatory Commission (FERC) define el concepto de medición avanzada o "advanced metering" como:

Medición avanzada es un sistema de medición que registra el consumo del cliente, y posiblemente otros parámetros, cada hora o más frecuentemente, y que provee para transmitir este registro diariamente, o más frecuentemente, a un centro de recolección de datos usando una red de comunicaciones.

El concepto fundamental en la definición de medición avanzada envuelve muco más que un metro capaz de medir en intervalos frecuentes. La medición avanzada se refiere a la medición, red de comunicaciones y al sistema de

C00243

recolección y de procesamiento de datos. Esta infraestructura se conoce como la infraestructura de medición avanzada. En nuestra opinión el espíritu del mandato de EPAct 2005 es precisamente el desarrollo y utilización de esta infraestructura de medición avanzada para proveer a los clientes mejores maneras de manejar su consumo eléctrico al poder responder a cambios en precios de la electricidad, o a incentivos diseñados para reducir consumo (ejemplo, "demand side management").

La medición avanzada apoya el uso de tarifas basadas en tiempo de uso ("time of use" o TOU por sus siglas en inglés) de una forma moderna y creativa. La medición avanzada permite mejorar el servicio que ofrece la compañía de electricidad al cliente, reducir el robo de electricidad detectando intervenciones con el sistema, permite monitorear la calidad de la potencia servida al cliente, mejora el manejo de apagones, mejorar el pronóstico de demanda, y la gerencia de los equipos de la compañía identificando con precisión la carga a servir por una línea de distribución o transformador específico. Este último punto permite que la compañía de electricidad escoja la capacidad de los equipos a utilizar en forma más eficiente y económica.

El uso de medición avanzada permite el mejor manejo de asuntos de importancia para el pueblo de Puerto Rico y para la AEE como lo son el manejo de la vegetación, y mejor monitoreo del nivel de voltaje en el punto de conexión del cliente. En el análisis presentado la AEE no considera ninguna de estas ventajas.

Otra oportunidad que provee la medición avanzada es proveerle información automatizada al cliente con la que pueda manejar su consumo. Por ejemplo el enviarle señales de precio a controladores de temperatura inteligentes, termostatos inteligentes, que ajusten la temperatura de sistemas de aire acondicionado para clientes residenciales con aire central o a clientes comerciales e industriales.

Nos confunde el análisis hecho por la AEE pues el mismo usa una sola curva de demanda agregada (la suma de la demanda de todos los clientes) para caracterizar todo día del año aunque sabemos que en sus operaciones la AEE usa una curva para domingo, otra para sábado, otra para viernes, otra para lunes y una quinta curva para martes, miércoles y jueves. Además, aunque la curva de demanda agregada utilizada fuera el promedio de las anteriores la misma es muy pobre en su resolución de demanda. A pesar de que no existe demanda agregada por debajo de unos 2,300 MW la curva tiene el rango en el eje vertical comenzando en cero (0) MW impidiendo apreciar los detalles de los cambios de la demanda según pasa el tiempo.

Otro asunto que nos causa confusión es el cómputo de una demanda base (cantidad a ser suplida por unidades base o de menor costo) no de 2,300 MW como muestra la curva de demanda sino de 3,074 MW, cantidad muy cercana a la demanda pico de alrededor de 3,600 MW.

También nos resulta confuso el llamado costo de generación para el 2009 entre

7 y 9 ¢/kWh que se presenta sin justificación alguna excepto que es el resultado del uso de un programa de computadoras. ¿Por qué si el costo de generación en el 2009 será de unos 9 centavos, hoy pagamos unos 19 centavos por kilovatio hora? Nos parece que las pérdidas en la transmisión y distribución, otros servicios y la compra de combustible no justifican la diferencia.

En realidad no podemos evaluar adecuadamente estos cómputos pues no tenemos acceso alguno a los datos usados para hacer los cómputos. Este es, en nuestra opinión, la falla mayor de todo este proceso, el proceso de la creación del documento que usa la AEE para justificar su decisión y el proceso de esta vista pública; el que otras entidades o el público no participaron de ese proceso. Y no es suficiente que haya un estudio de EPRI o de cualquier otra entidad externa a la realidad del país. En PR contamos con los recursos para atender apropiadamente este y otros asuntos energeticos, y en caso de que sea necesario recurrir a peritaje externo, existen recursos locales para evaluar los resultados de tales estudios. El EPAct 2005 ordena a las compañías eléctricas y las comisiones de servicio público, a AMBAS, evaluar la interconexión, la medición avanzada y otras disposiciones. En varios documentos federales, la Comisión de Servicio Público de PR aparece ejerciendo una funcion reguladora en PR al servicio eléctrico, aunque conversaciones con funcionarios de esa agencia nos indican que esto no es así. Ante la falta de un organismo como la Comisión, que en los EEUU vela mayormente por los intereses del ciudadano promedio, es imperativo al evaluar la implantación de EPAct 2005 que se identifiquen los mecanismos para lograr la justa representación de la ciudadanía en estos procesos. Y esto no implica que tengamos que esperar a que se legisle tal representación. Es nuestra esperanza que de estas vistas surja una apertura en la AEE que viabilice este proceso participativo en asuntos que directamente afectan a los clientes. Los procesos políticos tomarán nota y se legislará luego lo que sea necesario sobre esto. Podemos actuar ahora.

Sugerimos que no se abandone la consideración de medición avanzada por los beneficios de conservación y mejoras al servicio que recibe el cliente que esta medición puede traer. Recomendamos re-evaluar estas medidas, no sólo desde el punto de vista económico, sino también considerando los beneficios ambientales y sociales de esta tecnología.

Comentarios Finales

La historia de la humanidad está llena de ejemplos en donde países, personas u organizaciones han estado en momentos cruciales de decisión que marcaron su destino. Lo triste en muchos casos, es no darse cuenta en ***esos*** momentos de la importancia de los mismos. Puerto Rico enfrenta un momento crucial en el desarrollo de sus recursos energéticos. Salieron del pais en el anio 2006 sobre $6,000 millones para la compra de combustibles fosiles (estudio del Dr. Alameda, RUM). En PR, donde NO tenemos ningún combustible fósil, debemos explorar TODAS las posibles alternativas y evaluarlas no sólo en términos de costo-efectividad, sino también en términos ambientales y sociales. Es importante usar un marco de referencia mayor al ciclo político de cada cuatro años, y entender

que el problema es mucho más complejo que meramente reducir el costo de la energía eléctrica a corto plazo. El Gobierno tiene la obligación de tomar decisiones, posturas y realizar inversiones que a corto plazo tengan un costo económico mayor que otras alternativas, pero que a largo plazo son mejores no sólo en términos económicos, sino también ambientales y sociales. Recordemos que las decisiones de infraestructura que tomemos hoy estarán con nosotros por los próximos 30, 40 años.

Entendemos que la AEE vele por sus intereses y su salud financiera, al igual que sus compromisos con los bonistas. De igual forma, entendemos y apoyamos el derecho que tiene todo cliente, residencial, comercial, industrial, de tener acceso a información sobre el servicio eléctrico que recibe, a como se usan los dineros que paga por el servicio, y oportunidades por ahorrar en el servicio eléctrico a través de programas o tecnologías disponibles ahora o en un futuro cercano. La AEE y sus clientes no tienen porque tener una relacion adversarial, si queremos que PR enfrente exitosamente los retos que impone el presente estado mundial de los combustibles fósiles y nuestra dependencia de éstos. Para lograr mantener la confidencialidad necesaria en la información de la AEE, pero a la vez asegurar que los clientes tengan justa representacion, es por tanto necesario que en el desarrollo de los reglamentos relacionados a las disposiciones de EPAct 2005 participe algún organismo cuyo primordial fin sea asegurar el mejor trato y las mejores oportunidades para los clientes, con el mínimo de obstáculos y barreras regulatorias y económicas. Ofrecemos como opción en este proceso participativo el Instituto Tropical de Energía, Ambiente y Sociedad (ITEAS) del RUM. En ITEAS tenemos representadas sobre 15 disciplinas, y tenemos un compromiso con un futuro sostenible para PR donde se trate la situación energetica desde una perspectiva que integre la economía, el ambiente y la sociedad.

Solicitamos la oportunidad de participar en la consideración que la AEE tiene que hacer en o antes del 6 de agosto de 2008 sobre otras disposiciones del EPAct 2005 pues la ciudadanía tiene mucho que ganar si las mismas se atienden apropiadamente. En especial es de suma importancia la participación ciudadana ACTIVA, no sólo a traves de vistas públicas como esta, en el análisis e implantación de la *Sección 1251 Net Metering and Additional Standards* de EPAct 2005, pues esta afecta directa y positivamente a la ciudadanía. Una estructura colaborativa entre la AEE y la ciudadanía para considerar la medición neta y las otras medidas pendientes, permitiria atender las preocupaciones socales y ambientales, además de participar en la creación del reglamento que regirá estas prácticas. Sería un ejercicio muy saludable y mejor sintonizado con los tiempos que vivimos, tiempos donde los ciudadanos a nivel mundial tienen mayor participación de la que ofrecen, por ejemplo, estas vistas. Nuevamente nos ponemos a la disposición del funcionario a cargo de esta tarea en la AEE para viabilizar esta colaboración.

Hacemos un llamado urgente al Director Ejecutivo de la AEE, a la Junta de Gobierno de la AEE y su Presidente, para que se alcen en una gesta histórica de apertura de la Agencia al ciudadano promedio, a una nueva era donde la AEE facilite la transición de PR hacia recursos y prácticas energéticamente

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sostenibles. En varias ocasiones hemos conversado tanto con el Director Ejectivo como con el Presidente de la Junta de Gobierno de la AEE, y entendemos que existen los espacios y la disposición para lograr ese futuro sostenible, por Puerto Rico. Esta apertura, en lugar de debilitar a la AEE, tiene el potencial de mejorar sus relaciones con el Pueblo, cumplir de mejor manera con su misión y abrir nuevas oportunidades de crecimiento económico para la AEE. Es fundamental establecer nexos entre la AEE, otras agencias de gobierno, la industria, el comercio y la ciudadania a través de los cuales pasemos de una relación adversarial a una colaborativa, que pasemos de la desconfianza mutua a un compromiso serio y duradero por el bien común, por el bienestar social, ambiental y económico de Puerto Rico.

Atentamente,

Dr. Agustín Irizarry Rivera, PE
Catedrático e Investigador
Profesor Destacado de Ingeniería Eléctrica y Computadoras, RUM
Ingeniero Electricista Distinguido, CIAPR

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9 de Julio del 2007

Ponencia ante las vistas publicas de la Autoridad de Energia Electrica (AEE) celebradas para cumplir con los requisitos de la Energy Policy Act 2005 (EPAACT05-P.L. 109-58), titulada CONSIDERACION DE LOS ESTANDARES DEL EPACT 2005 "TIME BASED METERING AND INTERCOMMUNICATION STANDARDS FOR DISTRIBUTED RESOURCES (Consideracion), Preparado por: Division de Planificacion y Estudios, Junio de 2007

Salon de Actividades en La Guancha
Ave. Santiago de los Caballeros
Sector La Guancha,
Ponce, PR

Senores:

En dicha Consideracion, la AEE expresa preocupacion sobre "Eefectos de Interconectar Generadores en el Sistema de Distribucion", que tenemos que pensar estan al alcance resolver con los recursor con los cuales la Agencia debe disponer. No puede ser tan totalmente impractico, antieconomico y hasta peligroso hacer estas interconecciones como se esta hacienda a traves de el mundo entero, en lo que ya son millones de instalaciones, sin los posibles problemas a los cuales aluden.

Los controles y tecnicas para evitar cualquier problema ya existen. Estan en Alemania, Espana, California, Hawaii y en muchos sitios a la vista de todos. No es tan nuevo para que no existan soluciones a estas preocupaciones. La adopcion de la tecnologia ya existente es crucial para no atrasar mas la oportunidad de progreso economico y estrategico de nuestros ciudadanos, comecrciantes e industriales.

Hay paises y regiones que ya tienen metas y fechas especificas de producir desde 20%, y hasta el 100% de su energia total con fuentes renovables, reduciendo su dependencia y contaminacion en una forma seria y responsible. Se esta perdiendo de vista que cada instalacion generatriz tipica consume combustible que en realidad ni sabemos su costo ni su efecto ecologico para el futoro.

Ademas es obvio que debemos liberarnos lo mas possible de combustibles cuyo precio, calidad, y disponibilidad estan en manos de gobiernos y politicas mundiales abiertamente contrarias a nustro sistema de vida. No hacerle frente activo y urgente a esta realidad se podria cataloger de una falta de resolucion conciente a estas realidades.

En mi casa hay un sistema fotovoltaico en uso. Tengo lo se llama "conocimiento de causa" . seria triste pensar que los autores de las consideraciones y "preocupaciones"

expresadas en esta convocatoria aVistas Publicas no puedan cualificarse en este aspecto, ni tener a su alcance recursos al efecto.

Hay una realidad practica que se tiene que considerer. Actualmente, el costo de un sistema fotovoltaico es alrededor de unos $12.00 por vatio nominal instalado. Con ayudas economicas casi insignificantes disponibles, el incentive del ciudadano, comerciante o industrial es rebajar su gasto economico en su consumo electrico por el alto costo en Puerto Rico, aun sin mirar al futuro. Ya hay un claro esfuerzo en conservacion. Ahora se contampla produccion. La interconeccion, la disponibilidad de tarifas variables (del tipo TOU – "Time of Use" y otros) si son ayudas importantes, pero nunca seran la motivacion de inversion con la oferta acctual de la AEE de acreditar solo el Costo Diferido a el sobrante de produccion que pudiera crearse.

La procupacion expresa en esta covocatoria de que " La interconeccion de generadores al sistema de de distribucion puede tener un impacto economico en las companias electricas" (lease AEE) es un casi invisible.... Puedo demostrar por records llevados por mi persona con el sistema instaladoen mi casa, (disponible para verificacion por sus tectnicos), lo siguiente:

1) La capacidad nominal de los 15 paneles fotovoltaicos de 170 w cada uno (capacidad nominal de 2,550 w, o unos 2.5 kw) nunca han producido mas de 1,500 w. Esto es approx 60% de lo optimo, que se acerca a el 75% que la industria estima que es promedio. La curva de produccion es muy gradual, empezando y terminando e cero, con la produccion de mas de 1,000 w empezando a las 3 horas de amanecer hasta unas 4 horas antes de atardecer, que en un dia tipico serian unas 6 horas. Esto podria representar en teoria un maximo de 7.5 KW-HR por dia, unos 225KWH por mes, de un consume mensual de alrededor de 1,300 a 1,500 KWH por mes.Hay muy pocos momento en el dia promedio cuando coincidiria un sobrante, y seria muy suave su entrada y salida. Compara eso con el golpe que una planta electrica suelta cuando se sale de secuencia de 10, 15 o 20 KW.

2. Aun presumiendo que dispongo de $25,000.00 para gastar en solo producir para interconectar mi sistema con, digamos, hasta 10KWH por dia, (3,650 KWH por cada 12 meses), necesitariamos unas 70,000 instalaciones para equivaler al 1% de de la produccion annual de la AEE de unos 24,8to Gwh. Con un 2% de limite, la mayoria de las regiones controlan estas instalaciones para el futuro (California planea tener 1,000,00 de instalaciones para el 2010, con un 5% de participacion

   Ni el bolsillo ni el sistema de la AEE esta en peligro por mucho tiempo. Sin embargo, si pensamos que cada barril de petroleo produce unos 550 KWH, los sistemas fotovoltaicos ayudarian a rebajar nuestra dependencia de los combustibles fosiles, y rebajar nuestra produccion de contaminacion.

CONCLUSION INESCAPABLE:

Los sistemas fotovoltaicos (y cualquier sistema de produccion electrica removable por medio removable) es positive para la economia y salud de Puerto Rico.

Todo incentive economico, con ejemplos de otras partes del mundo, son buenos y necesarios. para Puerto Rico. Cuanto antes, major.

Respetuosamente sometido, con interes y disponibilidad de tiempo y recursos para lograr las metas expresadas por la AEE al respecto,

Peter W. Sinz PE
Calle Jaen F-12
Vistamar Marina Este,
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P.R. 00983

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000252

Estimado Director Ejecutivo AEE, Oficial examinador de vista, consultor jurídico de la Autoridad de Energía Eléctrica del Estado Libre Asociado de Puerto Rico, distinguidos deponentes, ciudadanos todos...En el asunto: CONSIDERACIÓN DE LOS ESTÁNDARES DEL EPACT 2005: *TIME-BASED METERING AND COMMUNICATIONS INTERCONNECTION STANDARDS FOR DISTRIBUTED RESOURCES.*

Expongo como ciudadano, consumidor residencial y usuario del sistema de la AEE, así como miembro asociado y fundador de la **Asociación Puertorriqueña para la Energía Verde Inc. (APEV).**

La Asociación Puertorriqueña Energía Verde (APEV) es una iniciativa comunitaria sin fronteras entre los municipios de Puerto Rico, con la misión de que en nuestro país, todo aquel individuo que quiera generar por sus propios medios, electricidad derivada de fuentes de energía renovable (entiéndase aire, agua, sol, termal y biomasa), sepa que tiene el derecho a hacerlo, con la misión personal de no seguir siendo vapuleados por los altos costos que el estado nos impone por su adicción al combustible fósil y la misión comunitaria de contribuir a un ambiente mucho más saludable para nosotros y para los que nos heredan.

El *Energy Policy Act 2005* (EPAct 2005) fue firmado el 8 de agosto de 2005. Este enmendó a la *Public Utility Regulatory Policies Act* (PURPA) (Título XII. Electricidad, Subtítulo E, Sección 111(d)), para requerir a las compañías de electricidad considerer adoptar nuevos estándares.

Provisiones Del Acta de Política de Energía del 2005:

Las provisiones adicionales en EPACT afectan el desarrollo de la generación distribuida (de ahora en adelante en este documento se referirá por sus siglas en ingles: DG), y la consideración de ello por consumidores y planificadores de sistema eléctricos y operadores.

Por ejemplo, la Sección 1211 de EPACT pide el desarrollo de una Organización de Confiabilidad Eléctrica (ERO) y la implementación del mandato con estándares de confiabilidad eléctrica ejecutables. Estos estándares probablemente afectarán la toma de decisiones en materia de inversión por compañías de energía eléctrica y sus evaluaciones de los méritos relativos de DG, junto con otras opciones de recursos.

La Sección 1221 de EPACT pide que el DOE estudie la congestión de transmisión y posiblemente designar áreas obligadas de interés nacional como corredores de transmisión eléctricos. El estudio de congestión de transmisión podría evaluar la utilización de opciones de DG para reducir la misma.

C00253

El Subtítulo de EPACT E contiene enmiendas al (PURPA).

La Sección 1251de EPACT pide la adopción de estándares para la medición neta; éstas pueden afectar la interconexión de sistemas DG con la red eléctrica.

La Sección 1252 de EPACT contiene estándares para la medición inteligente y fijación de precios en base a tiempo que son generalmente pensados ser "mecanismos de implementación importantes" para la consideración de inversiones en DG por compañías de energía eléctrica y consumidores.

Además, la Sección 1252 de EPACT también promueve programas de respuesta de demanda a escala nacional. Estos programas han sido mecanismos importantes para establecer incentivos financieros para que consumidores instalasen DG, y hacerlos funcionar en una manera que proporcionen carga máxima y ventajas de confiabilidad para el sistema eléctrico total.

La Sección 1253 habla de condiciones en las cuales la compra de electricidad de instalaciones de cogeneración o pequeñas instalaciones de producción de poder por las compañías de utilidades no es el mandatario.

La Sección 1254 de EPACT pide la adopción de estándares para la interconexión de sistemas DG y llama a los estados a que piensen en usar los estándares del Instituto de Ingenieros Eléctricos y Electrónicos (IEEE) 1547, como la base bajo la cual los estados ofrecerán servicios de interconexión. El IEEE 1547 implica un grupo de estándares (1547.1–1547.6) que IEEE requiere sea revisado cada cinco años.

Como parte de esta importante y crucial acta, la sección 1817 del Acta de Política de Energía (EPACT) de 2005, pide al Secretario de Energía conducir un estudio de las ventajas potenciales de cogeneración y pequeña producción de poder, conocido como generación distribuida, o DG. Las ventajas a ser estudiadas incluyen aquellas recibidas "directamente o indirectamente por una distribución de electricidad o abastecedor de servicio de transmisión, otros clientes servidos por una distribución de electricidad o abastecedor de servicio de transmisión y/o el gran público en el área servida por el servicio público en el cual el cogenerador o el pequeño productor de poder son localizados.

C00254

Las áreas específicas de ventajas potenciales cubiertas en el estudio **"THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION A STUDY PURSUANT TO SECTION 1817 OF THE ENERGY POLICY ACT OF 2005 – Feb 2007- Department of Energy United States of America",**

incluyen:

• Aumento en la confiabilidad del sistema eléctrico (la Sección 2)

• Reducción de exigencias máximas de ~~poder~~ Potencia eléctrica (la Sección 3)

• Provisión de servicios auxiliares, (la Sección 4)

• Mejoras de calidad de ~~poder~~ ENERGÍA ELÉCTRICA (la Sección 5)

• Reducciones del uso de tierra y gastos de adquisición de servidumbres de paso (la Sección 6)

• Reducción de vulnerabilidad a terrorismo y mejoras en resistencia de infraestructura (la Sección 7)

Requerimos que los hallazgos formulados en el estudio del DOE federal sean incluidos como parte de los hallazgos en el informe de esta vista pública. La APEV proveerá copia de los mismos como parte de esta ponencia en los documentos de anejo.

De acuerdo con el EPAct 2005 la determinación de adoptar o no los estándares *Timebased Metering and Communications* e *Interconnection Standards for Distributed Resources* se debe concluir para el 8-de agosto de 2007.

En la presentación entregada por la AEE establece que: "La Autoridad debe establecer si la implantación de cada estándar en Puerto Rico es apropiada para lograr los propósitos de PURPA. La determinación debe realizarse por escrito, tomando en cuenta los hallazgos y las evidencias que se presenten en vistas públicas."

La AEE es una corporación pública propiedad del pueblo de Puerto Rico y sus acreedores y bonistas son a final de cuentas, cubiertos con garantías dadas en base a un patrimonio nacional. Es a nos, el pueblo a quien se tiene que escuchar y servir con propósito óptimo y de futuro. Nuestra exigencia es de que se incluyan los hallazgos y evidencias que presentamos a favor del aumento en cuota de Energía alterna y la apertura a la DG.

000255

Una Breve Historia de la DG

El DG no es un fenómeno nuevo. Antes del advenimiento de la corriente alterna y turbinas de vapor en gran escala - durante la fase inicial de la industria de energía eléctrica a principios de siglo 20 - todas las exigencias de energía, incluso calefacción, refrigeración, la iluminación, y poder, fueron suministradas en o cerca de su punto del uso. Avances técnicos, escaladas en las economías en producción de poder y entrega, el papel creciente de la electricidad en la vida americana, y la regulación del fenómeno consumerista que colocaba la electricidad como un servicio público, todos gradualmente convergieron para permitir la red de escala de gigawatt en centrales termoeléctricas localizadas lejos de centros urbanos, con transmisión de alta tensión y líneas de distribución de voltaje inferiores que llevan la electricidad a prácticamente cada negocio, instalación, y a cada casa en el país.

Al mismo tiempo que este sistema de generación central evolucionaba, algunos clientes encontraron económicamente ventajoso instalar y hacer funcionar su propio sistema de energía eléctrica y sistemas de energía termales, en particular en el sector industrial. Además, las instalaciones con necesidades de poder muy confiable, como hospitales y centros de telecomunicaciones, con frecuencia instalaban sus propias unidades de generación eléctricas para usar como poder de emergencia durante interrupciones. Estas formas "tradicionales" de DG, aunque no forma parte de los activos en control de las utilidades, ofrecía ventajas producidas al sistema eléctrico total al proporcionar servicios a consumidores que la utilidad no tuvo que proporcionar, liberando activos para ampliar el alcance de servicios de la compañía de utilidades y promover la electrificación más extensa.

Simultáneamente, en Puerto Rico, en 1941 se crea la AEE con el propósito de conservar, desarrollar y utilizar, así como para ayudar en la conservación, desarrollo y aprovechamiento de las fuentes fluviales y de energía en Puerto Rico, en la forma económica más amplia.

Durante los años, las tecnologías tanto para generación central como para DG han mejorado haciéndose más eficientes y menos costosas. La implementación de la Sección 210 de (PURPA) provocó una nueva era de energía eficiente y sistemas basados en Energía renovable para aplicaciones de sistema eléctricos.

La sección 210 estableció una nueva clase de generadores que no pertenecen a la red de la utilidad llamados "Instalaciones Calificadas" (QFs) y proporcionó incentivos financieros para animar el desarrollo de la cogeneración y pequeña producción de poder.

C00256

Muchos QFs han proporcionado desde entonces la energía a consumidores “in situ”, pero otros han vendido el poder a precios y bajo términos y condiciones que han sido o negociadas o puestas por autoridades reguladoras estatales o utilidades no reguladas.

Hoy, los avances en nuevos materiales y diseños para paneles de fotovoltaicos, micro turbinas, motores recíprocos, dispositivos termalmente activados, ~~células~~ celdas de combustible, controles digitales, y equipos de monitoreo remoto, entre otros componentes y tecnologías, han ampliado la variedad de oportunidades y aplicaciones para el DG "moderno", y han hecho posible el adaptar sistemas de energía a las necesidades específicas de consumidores. Estos avances técnicos, combinados con la evolución en las necesidades del consumidor y la reestructuración de mercados al por mayor y de venta al detal para la energía eléctrica, han abierto más oportunidades para que consumidores puedan hacer uso de la DG para satisfacer sus propias necesidades de energía, así como para utilidades eléctricas explorar las posibilidades de suplir necesidades del sistema eléctrico con la DG.

Antes de 1970, la AEE se dedicaba a mercadear su servicio para promover venta de electricidad a gran escala. De esta manera se aprovechaban las instalaciones eléctricas y fué exitosa la corporación en base a una política pública en desarrollo económico industrial como centro.

A partir de la década de los 70's, los costos de producción, combustible y mano de obra aumentaron hasta un nivel de escasez en abastos y racionamiento de combustibles, convirtiéndose no en una inversión de capital y si en gasto recurrente que comenzó a gravar negativamente las finanzas de la corporación pública, por ende la de sus accionistas que a la postre como ya dijimos, expone económicamente al pueblo de Puerto Rico.

El 29 de junio de 1977 – Se firma la ley num. 128, creando la Oficina de Energía de Puerto Rico (OE) dentro de la AEE (la cual sería transferida en 1990 como dependencia del DACO) y se establece sus propósitos, funciones y deberes. En dicha ley se establecen los principios básicos de la política pública energética de PR en términos de “conservación, el desarrollo de fuentes renovables, los combustibles alternos y la planificación de asuntos energéticos”. En 1977 se crea el comité asesor sobre Energía del ELA.

En el 1993, el gobierno de Puerto Rico formula varias iniciativas para crear una política pública en el tema de la Energía. Primeramente, se crea la Administración de Asuntos de Energía (AAEPR), transfiriendo la OE a la misma, bajo la sombrilla del DRNA.

En los 90's se toman varias acciones específicas y sustancialmente importantes para la economía energética de Puerto Rico. En diciembre de 1993 el comité de cogeneración y generación de Energía del gobierno de Puerto Rico entrega un informe con recomendaciones sobre política pública energética de Puerto Rico. Es importante señalar que como parte de este comité se encontraban como miembros y firmantes de este documento directores de dependencias como: Junta de Planificación, AAA, AEE, Junta de Calidad Ambiental, Compañía de Fomento Industrial, Departamento de Recursos Naturales y DOE entre otros.

Este comité propone entre sus estrategias a corto (5 años), mediano (12 años) y largo plazo (20 años), lo siguiente:

- **Proveer incentivos económicos para usuarios de Energía eléctrica residencial y comercial para la compra de equipos y enseres con una alta clasificación de eficiencia energética.**
- **Proveer ayuda económica para proyectos pilotos dirigidos a la utilización de Fuentes renovables de Energía.**
- **Evaluar las Fuentes y/o mecanismos mediante los cuales la generación de electricidad y venta de la misma, se realice de la manera más costo-efectiva posible, incorporando los costos económicos, sociales, de salud pública y ambientales.**
- **Comenzar a generar energía utilizando como materia prima los desperdicios sólidos no tóxicos.**
- **Modificación de los códigos de construcción para permitir la incorporación de nuevas tecnologías, diseños eficientes y de conservación de Energía.**
- **Establecer normas de eficiencia energéticas para nuevas industrias como condición de permisos de operación y exención contributiva**
- **La reconstrucción del comité Asesor de Energía (L.128)**
- **La investigación científica en Asuntos energéticos de Puerto Rico**

"Hoy, en el año 2007, estamos en el año catorce (14), de este informe y la APEV exige se incluya en el informe final de estas vistas públicas, qué seguimientos, estudios y previsiones se le ha dado a tan importante e histórica pieza de política pública."

Es inmaterial la participación de la política partidista en la historia de este documento, ya que este comité fué configurado por directivos de agencias que establecen la política pública energética y ambiental del país. La AEE y AAA quienes responden directamente a sus abonados y accionistas, fueron parte de

este proceso, por lo que no hubiesen endosado este informe sin el visto bueno para establecerlo como política pública de la corporación.
Históricamente, representa un reto que la AEE de Puerto Rico mantenga el precio de la electricidad lo más bajo posible, se haga una inversión recurrente en tecnología en armonía con principios ambientales locales e internacionales y se readiestre a todo recurso humano con una verdadera base de provecho, que establezca una economía energética científica y de aprovechamiento óptimo de nuestros recursos.

"Estamos en espera de la firma del poder ejecutivo del gobierno de Puerto Rico, del proyecto de Ley #1212, para establecer una forma de venta de electricidad generada por fuentes renovables parecido al "net metering", que acaba de aprobar el legislativo. El mismo establecería la necesidad de que la AEE muestre las tablas tarifarias que aplicarían a esta modalidad de cliente-generador residencial (300 ~~Kv.~~ kwh diarios) y comercial (10 ~~Mw.~~ mwh diarios) y que la Administración de Asuntos de Energía de Puerto Rico, establezca los modelos de generadores a ser aprobados. La toma de decisión de la AEE sobre cambios tarifarios queda condicionada a nuestra aceptación de los mecanismos operacionales y de contrato aplicables así como a la firma de esta ley."

DG al día de hoy:
"Los paneles solares instalados en casas son generación distribuida. Un generador de emergencia detrás de una tienda de conveniencia es DG.
Un agricultor que usa la basura de sus propios animales para generar electricidad es DG. Un hospital usando una turbina de gas para la electricidad y reciclando el calor de desecho para lavar o proporcionar duchas calientes, es DG."

• La Generación Distribuida es actualmente parte del sistema de energía estadounidense. Hay aproximadamente 12 millones de unidades DG instaladas a través del país, con una capacidad total de aproximadamente 200 GW. La mayor parte de éstas son unidades de poder de reserva y son usadas principalmente por clientes para proporcionar el poder de emergencia durante tiempos cuando el poder por red no está disponible. Esta capacidad DG también incluye aproximadamente 84 GW en dominio privado para la producción combinada de electricidad y termal para ciertas plantas de fabricación, edificios comerciales, y sistemas de energía en distritos independientemente que proporcionan la electricidad y/o la energía termal para recintos universitarios y áreas urbanas. Mientras muchas utilidades eléctricas han evaluado los gastos y ventajas de DG, sólo una pequeña fracción de las unidades DG en servicio es usada para el suministro de sistemas de utilidades eléctricas y operaciones.

• Hay varios motivos económicos e institucionales por los que las compañías de utilidades eléctricas no hallan instalado e invertido mucho en DG. Por ejemplo, la base económica de la DG es una diferente de caso a caso, es muy específica,

individual y por área. Por consiguiente, muchas de las ventajas potenciales son más fácilmente capturadas por los clientes-generadores que aquellas por DG del lado de la utilidad. Esto ha conducido a la situación actual donde los modelos de inversión comercial para que utilidades eléctricas inviertan en DG no hallan surgido con tanto entusiasmo. Además, en casos donde las compañías de utilidades identifiquen oportunidades económicamente atractivas para inversión, hay a menudo una carencia de familiaridad con las tecnologías DG, que ha contribuido a la percepción de riesgos añadidos e incertidumbres, en particular cuando DG es comparado a soluciones de energía convencionales. Esta falta de familiaridad por no establecer programas pilotos, ha contribuido a una carencia de datos estándares, modelos, o instrumentos de análisis para evaluar DG o prácticas estándares para incorporar DG en la planificación de sistemas eléctricos y operaciones en el país. Los únicos modelos de DG que la AEE tiene documentado en su presentación son propulsados por energía convencional marrón (Eco Electrica, AES).

"Llamo la atención nuevamente al documento de 1993 en donde como parte de la política pública energética de Puerto Rico, se requería un estudio y proyectos pilotos sobre DG que tendrán que ser documentados en el informe final de esta vista como que se hallan llevado a cabo."

• DG ofrece ventajas potenciales en la planificación de sistemas eléctricos y operaciones. En una base municipal, hay oportunidad para que la AEE utilice DG para reducir cargas máximas, proporcionar servicios auxiliares como son: poder reactivo y apoyo de voltaje así como mejorar la calidad de poder. La Utilización de DG a nivel municipal puede alivianar la carga total del sistema municipal y mejorar la confiabilidad del sistema eléctrico en su totalidad. Por ejemplo, varias utilidades tienen programas que proporcionan incentivos financieros a clientes-generadores con unidades de DG de emergencia para ponerlos a disposición de operadores de sistema eléctricos durante períodos de demanda picos y en otros tiempos de necesidad del sistema.

La ley 145 aprobada en 2006, autoriza bajo la ley de Municipios Autónomos a la creación de corporaciones especiales de DG en cumplimiento de PURPA. Además, varias regiones han empleado programas de respuesta de demanda (DR), donde los incentivos financieros y/o tarifas son promocionados a clientes-generadores para reducir su consumo de electricidad durante períodos picos. Clientes-generadores que participan en estos programas usan DG para mantener sus operaciones cerca de lo normal mientras ello reduce su ~~uso de poder en horas pico~~ demanda. Para esto, es necesario que se estipule una nueva categoría de cliente en la AEE: el cliente-generador en niveles: residencial, comercial e industrial.

• Además de las ventajas potenciales para la operación y planificación de sistemas eléctricos, DG también puede ser usado para disminuir la vulnerabilidad del sistema eléctrico a amenazas de ataques terroristas u otras

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formas de interrupciones potencialmente catastróficas como desastres geológicos o atmosféricos para así aumentar la capacidad de recuperación de sectores de infraestructura críticos, definidos en el Plan de Protección de Infraestructura Nacional (NIPP) publicado por el Homeland Security Department, como son: telecomunicaciones, plantas químicas, agricultura y alimento, e instalaciones del gobierno. Hay muchos ejemplos de clientes que poseen y hacen funcionar sus instalaciones en estos sectores quiénes usan DG para mantener operaciones cuando la red está abajo durante interrupciones relacionadas con el tiempo o apagones regionales.

"En septiembre 2004, la tormenta Jeanne provocó pérdidas que rondaron los $11.0 Millones y gastos de $33.4 por daños al sistema de transmisión y distribución, siendo un evento menor dentro de la historia climatológica de Puerto Rico."

• En ciertas circunstancias, DG también puede tener efectos beneficiosos en el uso de tierras y necesidades de servidumbres de paso para transmisión eléctrica y distribución.

•Reglamentaciónes excesivamente estrictas por parte del estado para aspirar a tarifas eléctricas verdes, regulaciones ambientales, restricciones e imprecisiones en la permisología para la interconexión en la red, desempeñan un papel importante en la determinación del atractivo financiero de proyectos de DG. Estas reglas y regulaciones varían entre estados y territorios de servicio de utilidades, que en sí mismo puede ser un impedimento para desarrolladores de DG, contribuyendo al alza de costos en proyectos de DG más allá de lo deseable. Además, las utilidades, a menudo con el acuerdo de las oficinas de Asuntos de Energía estatales, tienen reglas y provocan gastos que causan impedimentos relacionados con el costo de estudios y seguros que desalientan la DG. Recientemente, han habido contundentes trabajos de investigación técnica que se dirigen a uniformar y resolver algunos de estos impedimentos, como el trabajo del Instituto de Ingenieros Eléctricos y Electrónicos (IEEE) para poner en práctica estándares de interconexión de DG uniformes. Además, el Subtítulo E – Enmiendas a PURPA del Acta de Política de Energía de 2005, contiene provisiones para que comisiones de utilidades públicas estatales adopten tarifas de electricidad a base de tiempo, medición neta, medición uniforme, estándares de interconexión uniformes, y programas de respuesta de demanda, los cuales ayuda a resolver algunos impedimentos relacionados con el costo de DG.

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"La APEV plantea que, a menos que la AEE tenga para nuestro estudio y comentario resultados de proyectos pilotos en Puerto Rico en DG a nivel residencial, comercial e industrial; que demuestren la necesidad de medidas restrictivas o mayores a las de otros estados y/o territorios de la nación, se utilicen los estándares de IEEE. Así también es preocupante que en esta vista la autoridad reguladora estatal, Administración de Energía de Puerto Rico, no presente su posición o la misma no se halla hecho pública como parte de la presentación de la AEE"

El dilema de "Costo" Vs. "Beneficios":

El resultado de esta carencia de integración de DG en el sistema eléctrico de Puerto Rico es la de que muchos de los beneficios directos, y prácticamente todos los indirectos de sistemas DG no son capturados dentro de la contabilidad tradicional de flujo de caja o "cash flow" en la AEE. Esto es principalmente el producto de una estructura reguladora histórica que ha producido inversión de capital específica y prioridades operacionales así como la tarea significativa de cuidar la red de generación central: líneas de energía, y subestaciones así como satisfacer las necesidades del consumidor de la energía eléctrica.

Desde su inicio, las comisiones reguladoras de utilidades públicas estatales han seriamente, perseguido lo mejor posible la combinación de servicios confiables y costos razonablemente bajos. Esta relación con las corporaciones de utilidades (algunas veces como colegas, otras como argumentadores), ha evolucionado en una serie de reglas generalmente aceptadas y prácticas comerciales en cuanto al método apropiado para estimar las propiedades de una tecnología, la utilización, la seguridad, y el valor público. Los sistemas DG ya que han sido principalmente soluciones basadas en el consumidor, generalmente se han desarrollado fuera del marco regulador tradicional.

"Como nota importante, la APEV pone en duda la efectividad e imparcialidad con la que se escoge para la mesa de directores de la AEE, aquellos que son representantes del interés público. La experiencia en los pasados dos años ha sido la de tener representantes que desconocen los procesos de reforma que los grupos de interés comunitarios, científicos y académicos estamos llevando en el país, no guardan relación alguna con los movimientos en defensa de nuestro patrimonio generatriz y han sido sumamente laxos y condescendientes en su rol como representantes".

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Ventajas de Sistemas de Generación Distribuidos (DG):

1. Tiempos de construcción más cortos

2. Riesgo financiero reducido por sobre o baja construcción de facilidades

3. Costo de proyecto reducido con el tiempo debido a mejor alineación de demanda incremental y suministro

4. Tarifas de ~~Kw.~~ KW más bajas debido a exenciones en permisos o menor gasto en permisología estatal/federal y municipal

5. Exposición considerablemente reducida al desuso de tecnología

6. Creación de trabajo local para fabricación, instalación/operadores y técnicos

7. Desarrollo de pequeños negocios e impuestos contra fabricación extranjera

8. Costo de unidades de generación menor, procesos industriales automatizados compartido con otras empresas de fabricación en serie (es decir, industria automotriz)

9. Comienzo de proyectos más cortos, permitiendo la capitalización rápida y evitando la exposición a climas económicos regulatorios

10. Reducción significativa de riesgos por interrupción por causa de combustibles (Aumentando la cartera de combustibles importados con "Energía alterna": solar, viento, biodiesel, hidro, termal)

11. Riesgo de cambio en precios de combustible fósil, reducido

12. Mayor ganancia contra inversión

13. Exposición reducida a fluctuaciones en tasa de interés

14. Potencialmente más y mejor análisis rutinario modular, para expansiones capitales

15. Salida múltiples para descontinuar proyectos, con diferentes niveles de riesgo

16. Capacidad de desplegar recursos portátiles a consecuencia de cambios en perfiles de demanda

17. Portabilidad = utilización de capacidad más Alta

18. Gastos de remediación reducidos al momento de decomisar proyectos

19. Eficacia de sistema más alta reduce la proporción de gastos fijos/variable (combustible)

20. Potencial de costos más bajos en repuestos hechos en línea de producción en masa

21. Desplaza aquella parte de la carga del cliente con las pérdidas de línea más altas

22. Desplaza aquella parte de la carga del cliente con las mayores exigencias de poder reactivas

23. Desplaza aquella parte de la carga de cliente con los gastos de energía marginal más altos

24. Interrupciones relacionadas con el clima (solar, viento), más fácilmente predichas y de duración más corta que fallos de equipo en plantas centrales

25. La capacidad de" hot swap" capacidad – cuando un módulo DG (panel, rastreador, inversor, turbina), no está disponible, otros módulos siguen funcionando

26. El emplazamiento de carga “load sitting”, reduce o elimina pérdidas de línea de transmisión eléctrica y líneas de distribución

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27. Estabilidad de sistema intrínsecamente mejorada debido a multiplicidad de entradas

28. Consecuencias regionales reducidas por fallo de sistemas

29. Transmisión mejorada y confiabilidad de distribución debido a reducción en carga pico, conducción y enfriamiento de transformador y conducción

30. Rápido "ramping" dentro del sistema de distribución, capacidad de reducir distorsión armónica a nivel del cliente.

Hay actualmente dos mecanismos primarios usados por las compañías de utilidades para tener acceso al lado del cliente-generador de DG para objetivos de confiabilidad:

• Varias utilidades ofrecen incentivos financieros a dueños de unidades de poder para propósito de emergencia para ponerlos a disposición de operadores de red durante tiempos de necesidad del sistema.

• Varias regiones ofrecen incentivos financieros o tarifas a clientes para reducir la demanda durante tiempos de necesidad de sistema (programas de respuesta de demanda), y algunos participantes en estos programas usan DG para mantener operaciones locales cerca de los parámetros normales mientras ellos reducen su demanda de la red.

Sobre la medición de tarifas en base de tiempo:

Entendemos la evaluación de datos históricos que dan base a la apreciación de que el "time based metering" no es necesario adoptarlo. La APEV basa su evaluación en datos diferentes, sobre todo en la evaluación de costos futuros de combustibles fósiles. La AEE solo proyecta los cambios en costos hasta 2009, cuando esta es una decisión que como ya se dijo en el informe "Política Pública Energética" de 1993, debe medirse a corto, mediano y largo plazo en veinte años de duración total. En un escenario a 20 años la AEE no puede pretender que se continúe en el modelo actual sin tomar en consideración escenarios y variables que como corporación, ya ha cuantificado, cualificado, previsto y llegado a conclusiones de política pública. No sería falta de visión. Sería ceguera.

la AEE de

Fluctuaciones y trastornos internacionales, falta de capacidad local para manejar estos trastornos, política energética desagregada y dispersa en varios organismos gubernamentales (hasta en el sector privado), ausencia de planificación estratégica que integre todos los sectores de la economía y aquellas que integren la salud y bienestar de nuestra sociedad son factores que si no se toman en consideración llevan a la AEE a reaccionar y no a evolucionar.

Actualmente, la educación ciudadana en conservación e implementación de modelos energéticos viene con completa credibilidad de la academia, los grupos comunitarios y los científicos. Grupos que a falta de incentivos por parte de la corporación y el estado, hemos tenido que aprender y aplicar el aprendizaje, pensando en el futuro de nuestros hijos y nietos. Se ha convertido de un asunto de política pública en un asunto personal que conlleva un cambio en estilo de vida.

La APEV recomienda que se trabaje una política de "Time Based Metering" considerando propiciar un ambiente económico para que ~~este modelo~~ crezca dentro de la red, una nueva clase de cliente: El generador DG (residencial, comercial y municipal).

En base a la ley #145, Ley #1212 u otras medidas de cartera económica como son: REC's y venta de electricidad verde se propicie una inversión que brinde estabilidad responsable al ciudadano y a la corporación.

La AEE tiene que brindar incentivos de tarifa, apoyo técnico y venta de productos y servicios. Su inversión contribuirá al bienestar ciudadano y del ambiente así como seguridad total del sistema y el país. Requerimos se haga una vista pública específicamente para discutir el modelo que la AEE está dispuesto a auspiciar en términos tarifarios y de interconexión, dando espacio a que la corporación estudie los modelos sugeridos y pondere un modelo administrativo puertorriqueño.

Incentivos económicos no tarifarios:

La experiencia mundial indica que productores residenciales con incentivos como REC's o Green Tags se organizan dentro de cooperativas y venden sus excedentes de energía y atributos, tanto al estado como a clientes privados con una certeza de que entrar a este cambio en tecnología es factible y deseable.

Esto, utilizando el mecanismo de Certificados de Energía Renovable (Renewable Energy Certificates o Green Tags), con los cuales individuos, industrias y gobierno podrán invertir en energía limpia sin el gasto de equipo que en energía renovable es un gasto principal y frontal (up front).

000266

En Estados Unidos y en el mundo encontramos ejemplos de comunidades enteras que invierten en sus equipos residenciales individuales y se benefician de los incentivos contributivos y reembolsos. El net metering históricamente, se promueve a través de la corporación de utilidades (en nuestro caso AEE), así como cooperativas y fundaciones establecidas para impulsar la energía verde a través de incentivos como REC's o GREEN TAGS.

Promotores (brokers) de energía que compran el derecho de vender los atributos energéticos que no se le vendan a AEE, se benefician por vender a mercados públicos paralelos. ¿Por qué no vender toda la energía y atributos a la Corporación pública? Hay varias razones.

Comencemos por definir el término "Atributos" en un REC. Los Certificados por Energía Renovable, representan los atributos de mejoras al ambiente, sociedad así como otros puntos positivos más allá de la generación de electricidad por fuentes renovables:

•Evitar impactos al ambiente. La compra de REC's y energía renovable impide la gran mayoría de los impactos ambientales asociados con la forma tradicional de generar energía eléctrica, ayudando a proteger la salud del ser humano y de lo que lo rodea.

•Alcanzar los objetivos ambientalistas en una organización. El reducir el impacto ambiental de una organización es una de las motivaciones principales para comprar REC's. Por ejemplo, comprar REC's puede ayudar a alcanzar una reducción significativa en los gases de efecto invernadero. Si una organización esta interesada en obtener una certificación ISO-1401, por su cuadro ambiental, el ser parte de un programa para reducir emisiones provocadas por el consumo/producción de energía es una parte importante como parte del proceso para obtener esta certificación.

•El comprar REC's demuestra liderato cívico, manifestando que la organización esta dispuesta a actuar con pronunciamientos en pro del ambiente y la sociedad. También demuestra una responsabilidad social hacia sus usuarios, la mayoría de los cuales favorecen la utilización de fuentes renovables de energía.

•Generación de publicidad positiva. La compra de certificados de energía renovable genera un reconocimiento público y de relaciones públicas que no hay campaña de publicidad o de medios que pueda adquirirla. Compañías que constantemente están en la mirilla pública necesitan ser proactivas a las preocupaciones en el tema ambiental que consumidores, inversionistas, cuerpos reguladores así como otros constituyentes manifiestan y fiscalizan. Agencias y grupos promotores de la energía verde como lo son la EPA, APEV u otros proveen asistencia para alcanzar grupos sociales y demostrar los logros de la organización a través del REC.

000267

•Comprar REC's crea una diferencia entre su producto o servicio y todos los demás. Una compañía podrá ser capaz de diferenciar su producto o servicio por ejemplo, ofreciéndolo como "hecho con energía renovable" o "ambientalmente neutral". Se podrían crear campañas entre los generadores de energía renovable y las compañías de productos hechos a través de REC's. Se ha creado un logotipo que con el permiso correcto, las compañías podrán colocar en los empaques de aquellos productos certificados para indicar el porcentaje de energía renovable utilizado en la confección del producto o la operación de la compañía.

•La compra de REC's estimula la economía local. Ya que la generación de energía es local, empleos se crean para la instalación y operación de facilidades de generación. La generación de electricidad por renovables también eleva la taza contributiva y provee ingreso adicional al agricultor y a comunidades rurales, siendo una oportunidad importante para crecimiento económico en una economía madura, pos-industrial como la de Puerto Rico.

•Transformación en los mercados económicos locales. La compra de REC's reduce el impacto a largo plazo en los costos de producción y transforma el mercado tradicional, creando mercado de tecnologías asociadas a la energía renovable. La gran mayoría de estas tecnologías no están en producción en masa, pero sus costos de producción caen dramáticamente mientras el volumen de producción aumenta, convirtiéndose cada día en una alternativa más atractiva.

Históricamente a nivel mundial y nacional, la batalla para la implementación de modelos energéticos renovables ha surgido de las Universidades, comunidades, organizaciones de acción comunitaria y del pueblo.

Con un mercado libre en Certificados de energía, grupos de acción comunitaria como el nuestro podrán iniciar cooperativas entre los ciudadanos/municipios productores, firmar en exclusividad sus atributos para convertirlos en REC's y estos ser vendidos a ciudadanos y empresas con conciencia ambientalista pero sin los recursos para ser productores de electricidad por medios renovables.

Por último, la ganancia neta del REC se convertirá en dinero para los productores de energía, instrumentos de educación pública, becas estudiantiles para el estudio ambientalista y reembolsos.

Las cooperativas en EU son productoras masivas de energía limpia que venden su energía a las compañías de utilidades y a nivel municipal, venden los atributos en forma de certificados de energía para impulsar el establecimiento de nuevos productores de energía renovable. Este mecanismo (REC's), es reglamentado por la EPA , US Department of Energy, Green-E y el Laboratorio Nacional de Energía Renovable (NREL), entidades reglamentadoras que aplican sus poderes y tienen inherencia en el ELA.

000268

"Cabe señalar que el mismo beneficio y responsabilidad que tendría cualquier entidad privada reglamentada para la venta de REC's, la tiene la AEE. Es una exigencia a nivel federal que el estado o territorio promueva activamente este mecanismo de inversión vis a vis el net metering y la venta de energía verde."

Sobre el "net metering" y la posición de APEV en la instalación, facturación y crédito:

Entendemos que el contador deberá ser instalado por las mismas personas que instalan y certifican el mismo actualmente. El equipo (contador) podrá ser cobrado al cliente residencial o comercial a través de débito en los créditos que acumule el productor de energía renovable. Otra forma es a través del Cargo Fijo por Servicio de Cuenta que se cobra en la factura de AEE. Veamos lo que dice el nuevo modo de factura de la AEE:

Cargo Fijo por Servicio de Cuenta
Incluye los costos de equipo de medición (contador) y cargos administrativos. Este cargo se mantiene igual desde el 1989, a pesar de que los costos operacionales han aumentado.

"Nos oponemos a que la AEE haga cambios tarifarios sustanciales a este renglón, sobre todo cuando por primera vez en décadas, los cargos fijos por servicio de cuenta se aplicarían en tecnología que beneficiará directamente al residente y al comerciante."

Está disponible la tecnología para medir en ambas direcciones el flujo en el contador. No nos oponemos que como medición adicional, los equipos de los productores de energía renovable incluyan internamente una medición de entrada de energía fotovoltaica y/o eólica, pero no como parte del contador.

"De no ser así, cualquier requerimiento adicional de medición será provista por la AEE. Así también la AEE deberá proveer a los productores, cuales serán los parámetros técnicos y de seguridad mínimos necesarios para certificar a un productor de energía renovable. Estos parámetros deberán ser realista en términos del equipo certificado y estar acordes al estándar utilizado en la nación norteamericana en equipos residenciales y comerciales, partiendo de las regulaciones de EPA, ANSI, NEC, IEEE, UL y la Administración de Asuntos de Energía de Puerto Rico."

Es de hecho a esta última, a quien recomendamos como agente certificador del estándar de equipos a ser instalados por residentes-productores y/o comerciantes-productores.

000269

Entendemos que los cargos normales por servicio ya están detallados como parte de la nueva factura que dio a conocer la AEE. En todo momento se entiende que la cuota por cargo fijo por servicio de cuenta será cobrada a todo residente conectado a la AEE. Sin embargo, la AEE tiene que definir el renglón de Compra de Combustible, ya que los productores de energía renovable serán reflejados en la factura de AEE en el renglón de Compra de Energía y tiene que haber un cómputo que amortice el combustible sobre la compra de energía.

Veamos la explicación que somete la AEE como texto:

Compra de Energía
Costo de la energía comprada a los productores de electricidad. Esta relación contractual nos permite reducir la dependencia del petróleo y diversificar las fuentes de combustible. De no haber sido así el factor de ajuste por combustible hoy sería mucho mayor.

Compra de Combustible
Costo por la compra de combustibles derivados del petróleo. Actualmente representa más del 50% de la factura porque dependemos un 73% del petróleo. Si sigue bajando el precio mundial del petróleo, veremos una reducción en las facturas de octubre, noviembre y diciembre de 2006.

Entendemos que el cargo mínimo a cobrar a un productor de energía es equivalente a el cargo mínimo que se le cobra a un consumo cero (0) de electricidad durante un periodo de facturación. La AEE deberá diseñar como parte de su lugar en la red cibernética, una página en donde los productores puedan ver en tiempo real, lo que entra en producción de energía renovable a la AEE por su generación. Ya la corporación mantiene este servicio para todos sus clientes, lo que tendría que especializar es al renglón de producción residencial y comercial. La APEV puede proveer diferentes modelos para este mecanismo.

Estamos de acuerdo en que cualquier sobrante de crédito generado al final del año fiscal sea manejado por la AEE. No estamos de acuerdo en que se maneje esta energía verde como créditos y/o rebajas para el sistema de educación u otra dependencia gubernamental en específico y de forma gratuita.

"La producción de energía cuesta en todos los niveles, aunque sea de fuentes renovables. Entendemos que esta energía sobrante deberá ser convertida por la AEE en REC's y ser puesta a la venta y/o dado como rebates (reembolsos) a nuevos productores de energía que entren a la red o a consumidores de la red con conciencia ambientalista que quieran ser parte de la diferencia."

La empresa privada y los ciudadanos privados deberán ser incentivados mediante créditos en el servicio eléctrico/fluvial a la presentación de REC's. La AEE puede vender una cartera acumulada de REC's tanto en Puerto Rico como en los estados de la nación norteamericana.

000270

Economía energética y responsabilidad laboral:

En la última parte de esta ponencia, la APEV señala y quiere motivar a uno de los factores más importantes para que ocurra un cambio de actitud en la AEE: sus trabajadores.

Ustedes que son los técnicos, administradores, gerenciales y obreros de nuestro patrimonio nacional energético tienen ante si una misión patriótica y heroica ante su pueblo. Pero no es sacrificio lo que exigimos, es visión.

Los momentos de bonanza y logros sindicales les han dado a cada uno de ustedes la oportunidad de crecer como una de las clases trabajadoras más educadas y de mayor responsabilidad del país. Sus organismos representativos han crecidos al igual que la corporación, midiendo y evaluando la bonanza histórica que la AEE le ha brindado a este pueblo y cual accionistas y bonistas, sus uniones se deben a ustedes. Llegó la hora de la planificación para ser mejores, eficientes y duraderos para nos, el cliente, nos la ciudadanía. La APEV entiende que muchos de los proyectos pilotos que se deben llevar a cabo pueden ser auspiciados, fundados y asociados con ustedes y sus representativos sindicales. Es hora de que todos invirtamos en un nuevo modelo energético para el país y ser socios de nuestro futuro.

¿Como será un Puerto Rico energizado por fuentes renovables y DG? Algunos cambios presumibles son:

•La economía energética será más descentralizada y eficiente, permitiendo que residentes, municipios y comerciantes logren sus propias metas energéticas (ahorro/conservación).

•La dependencia al combustible fósil declinará, permitiendo al gobierno canalizar mejor sus recursos.

•Debido a ello, la capacidad bursátil y financiera aumentará al ser mayor la inversión en nueva infraestructura, remodelación y menor en energía.

•El aire será más limpio, reduciendo las enfermedades respiratorias como el Asma, salvando vidas puertorriqueñas.

•A nivel global, contribuimos sustancialmente a disminuir la emisión de gases nocivos, reduciendo la amenaza de cambios climáticos abrupto y severos como: Huracanes tipo 5, inundaciones y sequías.

•Miles de empleos se crearán en Puerto Rico en la agricultura, manufactura y servicios relacionados a la energía.

000271

•Comunidades rurales se desarrollarán como productores de energía y se levantarán mejores y más eficientes infraestructuras de servicio de utilidades en la ruralía.

Agradecemos la oportunidad de aportar en esta vista con hechos e ideas para el mejor futuro de nuestros hijos y nietos.

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Energía Verde (APEV)

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Eric Martinot's Research Site

www.martinot.info

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Alliance to Save Energy

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American Coalition on Ethanol

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Economy

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American Council on Renewable Energy

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www.cleanegroup.org

Clean Energy States Alliance

www.cleanenergystates.org

Clear the Air

www.cleartheair.org

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Climate Solutions

www.climatesolutions.org

Database of State Incentives for

Renewable Energy

www.dsireusa.org

Energy Efficiency and Renewable Energy, DOE

www.eere.energy.gov

Energy Future Coalition

www.energyfuturecoalition.org

Environmental and Energy Study Institute

www.eesi.org

Renewable Fuels Association

www.ethanolrfa.org

Rocky Mountain Institute

www.rmi.org

Solar Buzz (news)

www.solarbuzz.com

Solar Energy Industries Association

www.seia.org

Union of Concerned Scientists

www.ucsusa.org

The **Network for New Energy Choices** is a New York based nonprofit organization committed to providing U.S. state and local governments with ideas and information to generate clean, affordable power from local, renewable energy sources. Working with a growing coalition of nonprofit groups, municipal officials, business leaders and academics, NNEC is promoting creative and objective ideas for financing community-based clean energy, helping to dispel misinformation about renewable energy in the media and advocating critical utility policy reforms that will usher in a new world of energy choices for all Americans.

Chris Cooper | *Executive Director*

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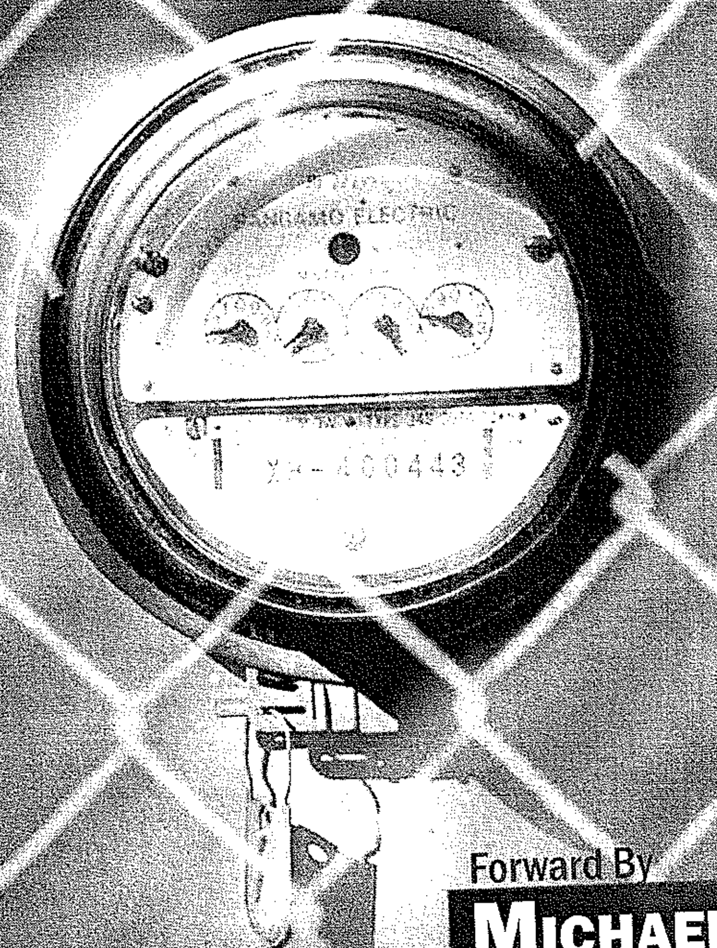
Network for New Energy Choices

FREEING THE GRID

REPORT NO. 01-06
November 2006

How Effective State Net Metering Laws Can Revolutionize U.S. Energy Policy



Forward By
MICHAEL DWORKIN
Professor of Law and Director of the Institute for Energy & the Enviroment
Vermont Law School

NETWORK FOR NEW ENERGY CHOICES

Freeing the Grid

How Effective State Net Metering Laws Can Revolutionize U.S. Energy Policy

Report No. 01-06 | November, 2006

Chris Cooper | *Executive Director*

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Network for New Energy Choices

Forward by **Michael Dworkin**

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Network for New Energy Choices

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All Hands on Deck

Recruiting Clean, Secure and Distributed Help for America's Energy Needs

When a sailing crew, in peril on the sea, saw storms ahead, the cry rang out: "All hands on deck!" For those who now see perils before us in the worlds of utilities and energy, there is a lesson to be found there.

In six years as Chairman of a state utility commission, I saw a lot of rough water and a few storms, but none as large and dark as those now facing our nation and our world. We face an "Energy Trilemma," – an energy world strained by the three forces of financial stress, environmental constraints and security risks. We all need solutions now that help us on some or all of these fronts, without making others worse. Yet, all too many of the remedies that some propose for one or two parts of the Trilemma tend to worsen the others. To make progress, we need to find new patterns, going beyond the way the electricity grid has functioned for almost a century. In a very real sense, we need to seek and welcome "new hands on deck."

Why do I say this?

Well, on the financial front, we all get monthly reminders of some of the past costs of our electric needs. But, few Americans have yet been shown the financial costs of the traditional ways of meeting future needs. Every look at increased demand and known resources says that strains will increase fast.

The North American Electric Reliability Council's 2006 annual report says that generators and utilities now have contracts with new plants for only one-third of what NAERC predicts will be needed. At the same time, Regional Transmission Organizations – the RTOs- cry out that we must set up payment plans right now to build capacity in years ahead, with billions needed to buy thousands of mega-watts from fossil-fired, centralized power plants. Yet, Edison Foundation's June 2006 study says that utilities' financial strengths have weakened and that they will need to raise rates to finance upgraded transmission and distribution systems. In other words, bringing in investments from old sources of capital will be difficult – which means costly.

On the environmental front, the dollar costs of sulfur containment and of nitrogen control are showing up in the bills charged by some utilities. The costs of mercury controls will come on soon. The financial costs of carbon capture lie ahead. The costs of land for power plants and transmission lines are rising fast. And, yet, those 'costs' in bills and rates, are but a small part of the true environmental costs that we all face, and an even smaller part of the true environmental costs that we are passing on to our children. We have now reached the point where environmental harms will be not just a cost, but a constraint on the electricity system.

When we turn to security, we all have seen images of flames and smoke when central focal buildings are destroyed, and we all know of days of loss and nights of darkness when the central grid fails for millions of us time after time. The costs of patching up and reinforcing the central station-focused grid are high indeed. But despite costly investments, it will never yield true reliability.

We have now reached the point where environmental harms will be not just a cost, but a constraint on the electricity system.

Why not ease this stress on the transmission grid by calling in the help of those who will invest in small, clean power plants installed right next to the electricity demand? A few utilities are taking the first-steps toward this transition (for example, Con Edison is seeking bids for 123 MW of demand-side resources -- including distributed generation -- to meet growing energy demands in 14 specific locations). But we need to pick up the pace. It is time for baby-steps to mature into healthy strides.

As a former rate-regulator, I know how it feels to have a utility come and say it needs to increase rates to cover new investments in transmission and distribution: it doesn't feel good at all. So, when we have a chance to recruit and encourage folks who will install their own small, clean generation, right next to the load that it will serve, the message is: "Many hands make lighter work; welcome to the task that we all face!"

What must we do to welcome those new hands? The Network for New Energy Choices has looked in detail at decades of experience in dozens of states. They offer here the "lessons-learned." And they do so, not as an academic exercise, but with tools for all of us to see and use.

What are some of the key lessons they present?

> That states and cities are taking up the challenge of meeting our national needs; truly thinking globally and acting locally. Efforts like NNEC's analysis can offer uniform models that will help meet larger goals. At the same time, the consistency of model laws and standards can ease the path for investors.
>
> To treat net-metering as a vital part of a larger effort to supplement our current centralized, fossil-fired, costly electric grid with clean, secure, and cost-effective energy resources. Thus, energy efficiency and renewable resources distributed throughout the system can both help, and be helped by, investments in clean net-metered generation.
>
> To keep our eyes open, as net metering occurs, for chances to transition to smart meters that incorporate time-of-use pricing and smart tariffs for all generators.
>
> To take a dozen steps, detailed within, to make that hope a true reality.
>
> And, perhaps most importantly, to encourage, not discourage, small, clean, distributed investments that can help all of us on all three fronts of our energy trilemma -- finance, environment, and security.

These are valuable lessons for utility regulators. I know from personal experience. They are also valuable lessons for us all.

And so I close by asking these questions, and thanking NNEC for help with the answers:

Is an energy storm coming?

It surely is.

Does America's electricity grid need help?

It surely does.

Can net-metering of clean, secure, distributed resources help meet the needs that we all face?

The folks that can do this are among the hands we want on deck.

How do we invite those hands to join us on the deck?

By using all the tools **NNEC** sets out for us in this report.

We've never needed the education that NNEC offers here as much as we do now – so my message to states and cities, to legislatures and commissions, is: "*Let's put these tools and lessons to work now.*"

The Network for New Energy Choices has looked in detail at decades of experience in dozens of states. They offer here the "lessons-learned."

Michael Dworkin, Professor of Law and Director of the Institute for Energy and the Environment at Vermont Law School, has also been a litigator for US EPA, a management partner in an engineering firm, and a utility regulator.

Professor Dworkin was Chair of the Vermont Public Service Board from 1999 to 2005 and he chaired the national utility commissioners' Committee on Energy Resources & the Environment. In 2003, on behalf of the Public Service Board, he received the "Innovations in American Government Award" from the Kennedy School of Government for helping oversee Efficiency Vermont's development into one of America's five most innovative and effective public service programs.

Michael is now a non-utility Trustee of the Electric Power Research Institute and was recently elected to Board of the American Council for an Energy Efficient Economy. For many years, he has helped pursue more sustainable energy portfolios, with special emphasis on energy-efficiency and renewable energy choices, including rural and agricultural options.

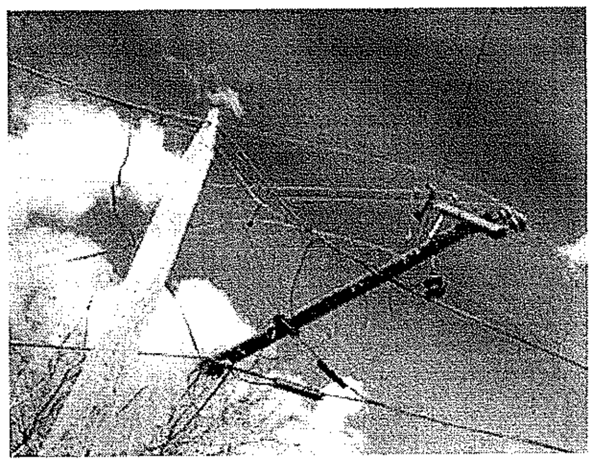
A graduate of Middlebury College and the Harvard Law School, Michael's work has focused on the points where technical, economic, and legal issues intertwine. He believes that: "*Energy policy is our world's most pressing environmental challenge, and environmental issues are the energy sector's most important constraint.*"

000297

American consumers face a crisis at the plug that is every bit as serious as the crisis at the pump. Recognizing an impending climate catastrophe and facing the unmet promises of electricity deregulation, consumers are beginning to revolt against rising utility costs.

This fall, for example, voters in Illinois waged a modern-day version of the Boston Tea Party, sending teabags to the state's utility in protest of projected rate increases of 22% to 55% in 2007. In Boston, homeowners and small businesses have seen electricity prices rise by 78% since 2002, from 6.4 cents a kilowatt hour to 11.4 cents a kilowatt hour.[1] As utilities scramble to address the reality of global climate change, retrofitting dirty, coal-fired power plants with carbon capture technology could raise the cost of electricity generation by 43% to 91%.[2]

States will be the Source of Innovative Energy Policies



Given relative inaction by the federal government, Americans are taking matters into their own hands. A record number of homeowners and small businesses are declaring their independence from utility monopolies by finding ways to meet their electricity needs more cheaply (and more cleanly) on their own. And more state governments are assuming control of their energy future by intervening to encourage this energy self-reliance.

For nearly 25 years, states have been the crucible for innovative policies to promote small-scale, renewable energy generation. By 2006, 36 states had adopted statewide programs that set rules by which customers who generate their own electricity can interconnect to the central transmission grid. Known as "net metering," these programs have been described as "providing the most significant boost of any policy tool at any level of government...to decentralize and 'green' American energy sources."[3] By compensating customers for reducing demand and sharing excess electricity, net metering programs are powerful, market-based incentives that states can use to encourage energy independence.

Lessons Learned

The Energy Policy Act of 2005 (EPAct) requires all states to "consider" a net metering program by 2008 or explain why their existing program is sufficient. Many states are already in the process of examining their existing programs to determine their effectiveness.

1 Smith, Rebecca (2006). "Emboldened states take charge of energy issues," Wall Street Journal. October 12. p. A6.

2 Intergovernmental Panel on Climate Change (2005). "Climate capture and storage," IPCC Special Report. Table 8.3a, p. 347.

3 Ferrey, Steven (2003). "Nothing but net: Renewable energy and the environment, MidAmerican legal fictions, and supremacy doctrine," Duke Environmental Law & Policy Forum. 14:1-120.

The Network for New Energy Choices (NNEC) has developed a metric to compare, grade and rank the 34 existing statewide net metering programs so that states can make a rational determination of how effective or ineffective their programs have been. We have determined which states are most effective and how states that have ineffective programs can adopt best practices to empower customers to generate their own clean energy.

By analyzing the evolution (and performance) of effective and ineffective state programs, we have identified pitfalls in the rulemaking process and ways to overcome them. Our comprehensive analysis reveals some fundamental lessons for states considering how to improve their net metering programs:

Ineffective Programs Discourage Small-Scale Renewable Energy

Most utilities are vocal opponents of net metering, mistaking self-generation as a revenue loss rather than as a demand-reduction strategy. Smart utilities should see every household and every small business as a potential contract generator, contributing clean, renewable electricity to the central transmission grid, helping the utility ensure reliable electrical service in a market strained by rising demand.

But in an effort to appease false concerns over lost revenue, many states have erected common barriers to self-generation by:

- Restricting commercial, industrial or agricultural customers from eligibility
- Limiting the size of eligible renewable energy systems
- Preventing customers from receiving credit for excess electricity
- Capping the total number of participants
- Charging discriminatory fees and standby charges
- Demanding unreasonable and redundant safety requirements
- Requiring unnecessary additional insurance
- Failing to promote the program to eligible customers

Analyzing the evolution of restrictive and ineffective regulations, we have discovered lessons for all states that want to avoid regulatory pitfalls and encourage energy independence.

Efforts to protect the economic interests of one sector (electrical utilities) often hurt other sectors in the state (like manufacturing).

Example: Indiana

Despite entreaties from the state's legislature, Indiana's regulatory commission decided to restrict commercial and industrial customers from participating in net metering. Indiana utilities argued that these customers, who could generate a substantial amount of their electricity demand themselves, would represent too great a revenue loss for the utility. As a result, Indiana's technology and manufacturing companies suffer from higher operational costs which limit their economic competitiveness.

Commissions that attempt to balance utility concerns with customer interests often undermine the intent of state legislators and adopt regulations that effectively destroy the program.

Example: Arkansas

In an effort to appease utility concerns that net metering represents a subsidy to participating customers, Arkansas' commission allowed the state's utilities to seize (without compensation) any excess electricity generated by customers at the end of every month. Denied fair compensation for excess electricity, only three Arkansas customers have enrolled in the state's program since it was initiated in 2001.

Effective Programs Revolutionize Energy Production

Several states have experienced rapid growth in small-scale renewable energy generation. In California, legislators had to increased the cap on total eligibility by 250% to meet demand (see page 14). In New Jersey, the state regulatory commission is overwhelmed with new applications.[4]

How do states craft an effective net metering program?

Focus on goals rather than on balancing interests
Allow monthly "banking" of excess electricity
Reduce unnecessary and burdensome red tape
Link net metering to statewide Renewable Portfolio Standards (RPS)
Create net metering as a comprehensive package of incentives
Require regular performance measurements

Example: New Jersey

In 2004, the Governor's Renewable Energy Task Force amended the state's net metering rules to help reach the state's ambitious goal of 20% renewable energy production by 2020. Jeanene Fox, the state's powerful utility board President, evaluated proposed changes with a singular focus: do the changes encourage or impede the development of a statewide renewable energy industry? Using this calculus, the state expanded eligible customer classes, instituted generous credits for excess generation and adopted the highest cap for eligible system sizes of any state in the nation. As a result, New Jersey has experienced the highest rate of enrollment of any state, increasing the number of installed solar systems more than fivefold.

Simple Solutions: Model Statutes and Regulations

Applying the lessons we have learned from 34 state net metering programs, the Institute for Energy & the Environment at Vermont Law School has crafted model statutory language for state legislators and model interconnection standards and regulations for state utility commissioners. As states consider adopting or expanding net metering programs in 2007, these models provide an easy way to emulate effective programs and avoid mistakes.

Ideally, a uniform national renewable energy policy would stem from federal leadership. The wide discrepancy in the design and implementation of 50 different state net metering programs has the potential to create uneven playing fields for renewable energy service providers and for regulated utilities. Uniform federal net metering standards could create a level playing field as well as provide greater regulatory predictability than a patchwork of 50 state-based programs.

4 Lacey, Stephen (2006). "The price of success: Inside the NJ clean energy program." RenewableEnergyAccess.com, October 10. Accessed at http://www.renewableenergyaccess.com/rea/news/story?id=45172

THE STATE OF NET METERING

Buried within the mammoth Energy Policy Act of 2005 (EPAct) is a little paragraph that could have profound effects on renewable energy generation in the United States.

In Section 1251 of EPAct, the U.S. Congress required every state to "consider" issuing net metering standards and by 2008 "make the determination" of such standards.[5] As legislative language goes, the word "consider" is as precise as words like "gourmet" or "sustainable". It is impossible to say what constitutes consideration or what distinguishes it from cursory rejection. The "determination" part of the provision isn't much clearer, but appears to require states to make a decision on whether to adopt some kind of net metering program by 2008. It is, however, silent on just what a good net metering program should look like.

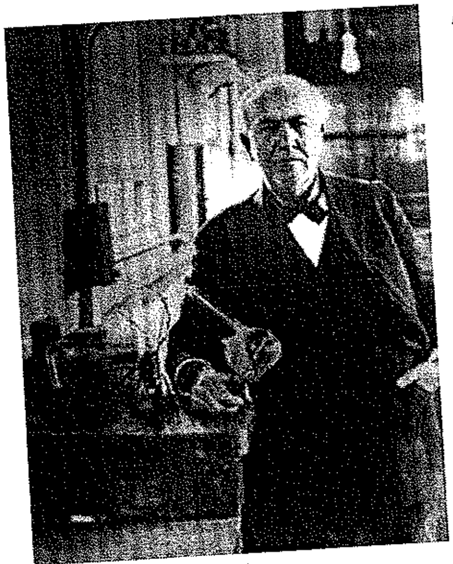
In its simplest form, net metering employs a standard electrical meter to record the flow of energy back and forth between a generator and the utility's power grid.[6] Since most meters are already capable of running in both directions, they provide an easy way to record the net excess electricity consumed or produced by participating customers during a given billing cycle. Across the nation, some 36 state legislatures and/or utility commissions have gone through the arduous process of crafting and passing 'net metering' rules - programs that require utilities to credit customers for generating their own electricity from renewable resources and to purchase any excess generation. Net metering is usually created as an incentive for homeowners and small businesses to invest in renewable power systems and to help decrease demand on the central transmission grid. In many states, the programs are seeing hundreds of new participants each year, jump-starting new renewable energy service companies and creating robust markets for off-the-shelf solar and wind systems.

But in many states, net metering has proven a poor mechanism for promoting small-scale, on-site renewable energy. By 2004, there were only about 15,200 customers nationwide participating in net metering programs, with 13,000 of them in California alone.

> Outside California, there are fewer than 2,200 customers in the United States participating in net metering programs.
>
> Three states have net metering standards and no participating customers at all.
>
> Six states registered five or less participating customers.
>
> In many states, more energy has been lost crafting the Byzantine interconnection rules governing net metering than has been generated by the programs themselves.
>
> In some states, the number of participating customers actually has decreased as many customers, deterred by burdensome paperwork requirements and hidden utility fees, simply dropped out.

5 Energy Policy Act of 2005. (2005) Subtitle E, Amendments to PURPA, Section 1251, Net Metering and Additional Standards.

6 U.S. Environmental Protection Agency, (2000) Net Metering, State & Local Climate Change Program. January. http://yosemite.epa.gov/OAR/globalwarming.nsf/UniqueKeyLookup/SHSU5BUTYL/$File/netmetering.pdf



Central Versus Distributed Generation

"I can only invent under powerful incentive,"

The preeminent industrialist financier, J. P. Morgan, who bankrolled much of Edison's early work with electricity, wanted to sell the machinery that generates electricity rather than get involved in the messy details of creating and selling the electricity itself. It is far easier to build and sell a widget, Morgan thought, than trying to manage an entire commodity market. But Edison preferred to keep a tight leash on the generation technology and wanted instead to profit from selling the electrical current, much like gas companies profited by selling gas.[8]

Unfortunately for us, Edison's vision prevailed. Over a century later, American consumers have come to depend on a rickety, unreliable transmission grid, stitched together from networks controlled by regional franchises. In our modern electronic society, it is increasingly a grid strained to capacity and unlikely to meet future demand.

It is also staggeringly inefficient. By the time electricity reaches the customer, nearly two-thirds of the energy in the original fuel has been wasted.[9] American consumers pay up to 2.6 cents per kWh for electricity lost in transmission.[10] Grid failures cost an additional $80 billion to $123 billion each year and add 29% to 49% to the cost of every kW of power transmitted in the United States.[11]

Had the U.S. electrical system followed J.P. Morgan's model, it may have looked far simpler and operated far more efficiently than our current model of centralized generation. Customers would produce their own electricity close to where it is consumed, with generators scaled to fit their demand and using fuels befitting the geography. Electricity guru Amory Lovins has documented over 200 benefits from this type of 'distributed generation' model – from reducing the number of customers affected by blackouts to making beneficial use of local fuels that would otherwise be discarded.[12]

While some utilities are beginning to understand the benefits of distributed generation and starting to invest in smaller, modular power systems, many continue to fight the participation of homeowners and small businesses by discouraging on-site renewable energy generation.[13]

7 Munson, R. (2005). From Edison to Enron: The business of power and what it means for the future of electricity. Praeger: Westport, CT (p. 16).

8 Goodell, J. (2006). Big Coal: The dirty secret behind America's energy future. Houghton Mifflin: New York, NY (p. 103).

9 Munson, R. (2006). Yes, In My Backyard: Distributed electric power. Issues in Science and Technology, Winter. http://www.issues.org/22.2/munson.html

10 Smeloff, E. (2005). Quantifying the benefits of solar power in California. Vote Solar, January. http://www.votesolar.org/resources/downloads/tools_Quantifying%20benefits.pdf

11 Casten, T. and Downes, B. (2005). The case for decentralized generation of electricity. Skeptical Inquirer, January/February.

12 Lovins, A. et al. (2002). Small is Profitable: The hidden economic benefits of making electrical resources the right size. Rocky Mountain Institute: Snowmass, Colorado.

13 U.S. Department of Energy. (2000). Distributed Generation: Securing America's future with reliable, flexible power. Office of Fossil Energy, Federal Energy Technology Center, October. http://www.distributed-generation.com/Library/FETC.pdf

In 1983, Minnesota became the first state in the U.S. to mandate net metering by legislative statute.[14] Proponents of the legislation believed that the program was an easy way to promote investment in renewable energy without spending a substantial amount of public funds. By providing a market mechanism for compensating customers for excess generation, the program was intended to offset some of the up-front capital costs associated with installing renewable energy systems.

After nearly 25 years of experimenting with net metering, there is a dearth of information comparing state programs and little guidance for states that must now consider establishing net metering policies or make improvements in existing programs. While some environmental groups and government agencies have issued reports attempting to evaluate the effectiveness of net metering, in most cases these reports have described the regulatory environment, evaluated differences between programs, and speculated about the effects of various rules. Most attempts to assess the effectiveness of net metering using more objective criteria have been hampered by the lack of available data on customer participation rates, the amount of renewable energy generated, or the effects of the programs on service quality.[15]

Starting in 2002, the U.S. Energy Information Administration (EIA) began collecting data on state net metering programs. The EIA has only made public data sets from 2002-2004. Because no complete set of data is available for all states since 2004, a comparative analysis of more recent policy changes is impossible. Instead, we take a snap-shot in time and compare the performance of state net metering programs at that time. The result is a comprehensive analysis of how different state net metering arrangements have affected customer participation over a specific time period (2002-2004). In many states, significant policy changes have occurred since 2004. Where possible, we have noted these changes and their effects on participation rates.

By comparing regulatory arrangements (and participation rates) across states from 2002-2004, we have identified how unnecessary regulations and burdensome requirements (often adopted at the behest of utilities opposed to net metering) have limited the ability of the programs to meet their intended goals. What emerges is a picture of state legislatures often undermined in their attempts to promote clean, distributed power by utilities that perceive on-site renewable generation as a threat to their bottom line. Taking the lessons learned from a quarter-century of net metering policy in multiple states, we attempt to dispel myths, identify best and worst practices and make recommendations for policy reforms.

What emerges is a picture of state legislatures often undermined... by utilities that perceive on-site renewable generation as a threat to their bottom line.

For over two decades, states have been the crucible for innovative policies to promoting small-scale renewable energy. Some states have seen remarkable success. Others have failed.

This report is a call to action. It is time to apply the lessons learned from successful (and unsuccessful) state net metering programs to reform and improve existing policies, to create new state initiatives where they do not exist and ultimately to adopt a model policy that offers new energy choices to all Americans.

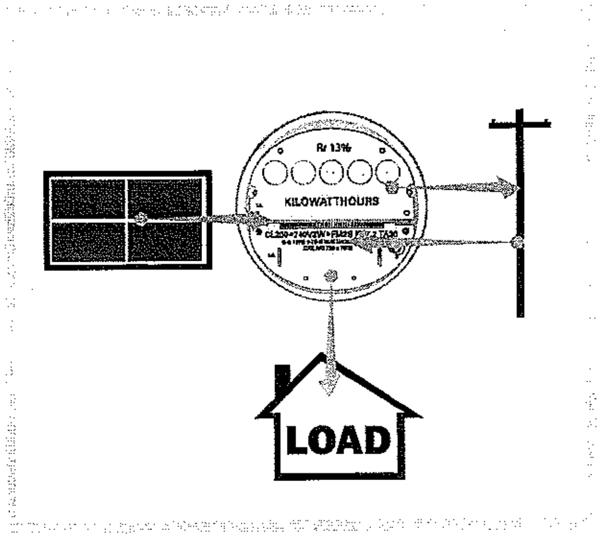
14 American Wind Energy Association. (2005) Small Wind in Minnesota. http://www.awea.org/smallwind/minnesota_sw.html

15 The Michigan Public Service Commission, for example, has attempted to make an accurate assessment of its state program since 1998. Their report was still in draft form as of October, 2006.

Methods of Metering Small-Scale Renewable Energy

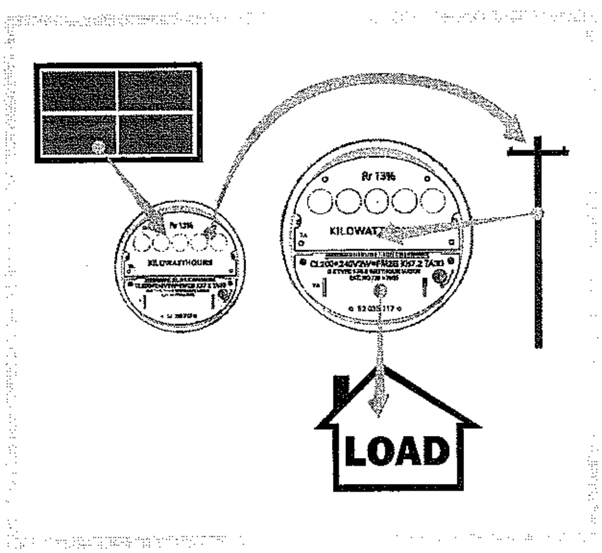
Net Metering

The most common method of "basic" net metering uses a single bi-directional meter that registers the flow of electricity in two directions to record the customer-generator's net energy consumption or production over a single billing period. The meter spins forward during periods of electricity consumption from the grid, similar to any ordinary meter. Alternatively, the meter spins backwards during periods of excess energy production to register the flow of electricity fed into the grid. Many existing meters have this capability. At the end of each billing period, the utility company bills the customer-generator only for the net energy consumed by the grid (the difference between the energy consumed and the energy produced on the grid). In the situation of net metering with rolling credit, the utility should credit the customer for any excess generation at the retail rate for electricity and carry that credit to the next billing period indefinitely.[16]



Dual Metering

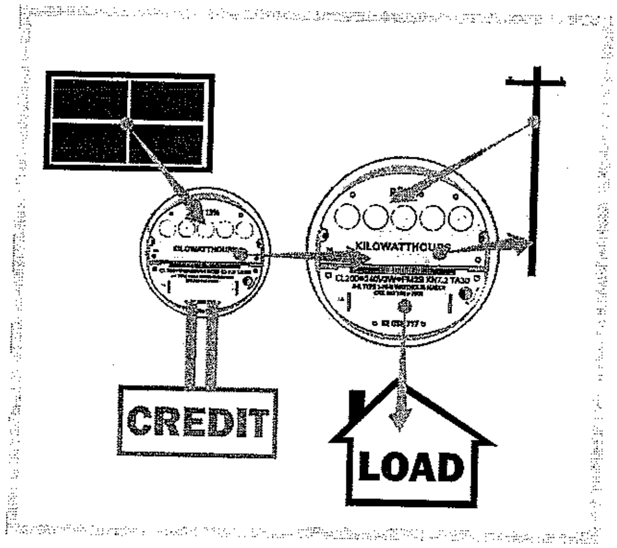
Dual metering, another method of metering, should not be confused with net metering. Unlike net metering, which uses a single, bi-directional meter, dual metering requires two separate meters: one to measure the electricity consumed from the grid and another to measure the distributed generation (DG) produced electricity sold to the grid. Dual metering typically costs more than net metering for both the utility and the customer. The customer generally pays for the secondary meter, while the utility incurs the extra administrative costs associated with processing the data from two separate meters.[17] Under dual metering, the customer-generator feeds any electricity produced from a DG-system directly onto the grid, which the utility purchases at avoided cost (the amount it would cost the utility to place the power in the grid itself) and credits the amount purchased to the customer's monthly bill. The key difference between net metering and dual metering is that a net metered customer receives credit at the retail rate (the price the electricity would cost the customer at the time it is used), while in dual metering, the customer receives the (much lower) avoided cost, or wholesale rate, for electricity generated by a DG system.



16 Hughes, Larry and Bell, Jeff. (2006) Compensating customer-generators: a taxonomy describing methods of compensating customer-generators for electricity supplied to the grid. Energy Policy. Vol. 34, No. 13. pg. 1532 - 1539.

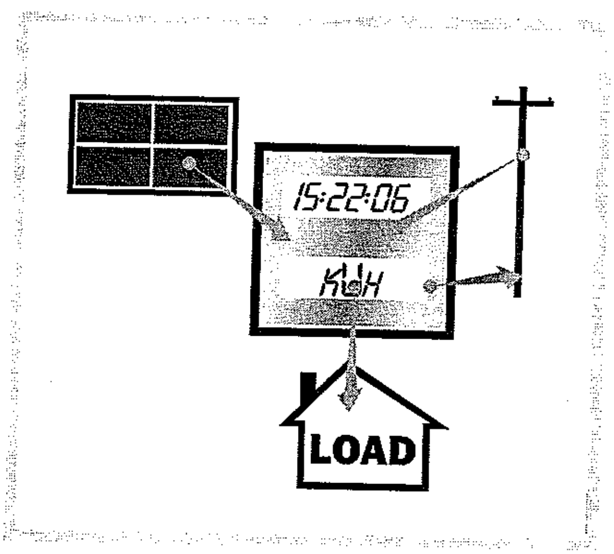
17 Wiese, Steven M., John E. Hoffner, Erin Scott, Jane Pulaski, Russel Smith. (2005) Interconnection and Net Metering of Small Renewable Energy Generators in Texas: Final Report of the Texas RE-Connect Project. Million Solar Roofs Project. June 11. http://www.treia.org/pdf_files/Final%20Report.pdf

Net Billing[18]



Another two-metered system, called net billing, uses a bidirectional meter to record the net energy consumption, while a secondary meter records the total output of electricity fed into the grid from the DG system.[19] As in bi-directional metering, the customer is credited the retail rate for the electricity generated. For some customer-generators, total output is awarded performance based incentives, such as Renewable Energy Credits (RECs), tradable commodities that represent the attributes of energy produced by renewable sources. However, for smaller PV systems, REC distributors often estimate potential output and award RECs based on that estimate.

Smart Metering[20]



A final type of metering system is smart metering. Smart metering allows customer to gauge the real-time price, or 'time of-use' rate, for electricity. This enables customers to base their electricity consumption patterns on the retail prices of electricity. The use of smart metering in conjunction with net metering encourages customer-generators to make more informed electricity consumption decisions, which can drastically reduce demand on the electricity grid as well as the customer's monthly bill. For example, customer-generators with smart metering reduce demand by producing their own electricity during peak load intervals (conveniently, the time when PV systems are at optimal performance), and reduce their monthly bills by performing energy intensive chores (like household laundry) when retail rates of electricity are lowest. Also, smart meters can differentiate between sources of energy and can track DG production, which can facilitate the use of performance-based incentives.

18 "Net billing" is sometimes lumped into the "net metering" or "dual metering" categories. As it is listed here "net billing", with net excess generation credited at the retail rate, falls more in line with "net metering". "Net billing" will be included in the definition of "net metering" for the remainder of the report.

19 Hughes, Larry and Bell, Jeff. 2006. Compensating customer-generators: a taxonomy describing methods of compensating customer-generators for electricity supplied to the grid. Energy Policy. Vol. 34. No. 13. pg. 1532 – 1539.

20 Similar to "net billing", "smart metering" will fall under the definition of "net metering".

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Limits on System Sizes

Most individual state net metering standards impose a limit on the maximum allowable capacity size of individual net metered systems, ranging from a system size limit of 10 kW in several states up to 1 MW in California and 2 MW in New Jersey.[23]

Many states restrict net metering customers from participating in power sales and subsequently discourage customers from investing in renewable energy systems larger than necessary to meet on-site demand.[24] In other states, statutory limitations on the size of eligible technologies prevent customer-generators from correctly sizing a renewable energy system to provide most (or all) of their on-site demand. For example, New Hampshire's net metering statute limits commercial customers to solar PV systems smaller than 25 kW. As a result, commercial customers with loads greater than 25 kW and the capability of installing larger systems are limited to a grid-tied system that can only generate the first 25 kW of their demand.[25]

Some of the least effective net metering programs do not allow customers to bank excess generation, letting utilities seize it at the end of a given monthly billing cycle.

Uniformity of size limits reduces regulatory confusion while promoting the broadest population of renewable energy generating systems. It is no longer uncommon to see renewable energy systems in the 100 kW to 2 MW range. Increasing the eligible facility size for non-residential systems also could encourage participation by large investors in net metering programs. Several project developers in Oregon, for example, have argued that the transactional cost of systems less than 100 kW are too great to interest large investment partners.[26] Projects like FedEx's 904 kW net-metered solar system in Oakland, California would not be possible under many states' current regulations.[27]

In 2005, the Federal Energy Regulatory Commission (FERC) issued uniform standards for interconnecting small generators and required public utilities that own or control interstate transmission lines to abide by the standards. FERC standards define "Small Generators" as having a capacity of no more than 20 MW and further create a special class of "Certified Inverter-Based Small Generating Facilities" no larger than 10kW.[28] For practical purposes, system size limits contained within state net metering regulations should reflect the limits defined by FERC. Should states adopt system size limits at all, they should limit eligibility to systems that qualify as "Small Generators" under FERC's standards - 10kW for residential customers and up to 20MW for commercial and industrial customers.

Restrictions on "Banking" Net Excess Generation (NEG)

When customers generate more electricity during a monthly billing period than they consume, some states allow customers to "bank" the excess generation. The utility credits the customer for any excess electricity generated in a monthly billing period and

23 Database of State Incentives for Renewable Energy (DSIRE). 2006. www.dsireusa.org

24 Maine Public Utilities Commission. (1998) IPP Net Metering News: Statement of Policy. April. http://www.i2p.org/news.htm.

25 Hamrin, Jan, Dan Lieberman, and Meredith Wingate. (2006) Regulators Handbook on Renewable Energy Programs and Tariffs. Center for Resource Solutions. March. http://www.resource-solutions.org/policy/TariffHandbook/Handbook_on_Renewable_Energy_Programs_&_Tariffs.pdf

26 Oregon Department of Energy. (2006) Net Metering: Comments by Kyle L. Davis of Pacificorp. July 10, 2006 Page 3 http://www.oregon.gov/ENERGY/RENEW/docs/ODOENetMeteringPaper-Revisions.pdf.

27 Corum, Lyn. 2006. Investing in a Clean Energy Future. Distributed Energy. July/August. http://www.forester.net/de_0607_investing.html

28 U. S. Federal Energy Regulatory Commission (2005) Standardization of Small Generator Interconnection Agreements and Procedures. 18 CFR Part 35 [Docket No. RM02-12-000; Order No. 2006]. May 12. http://www.ferc.gov/industries/electric/indus-act/gi/small-gen.asp

Most states that have adopted net metering statutes have done so in pursuit of the same goals:

To encourage greater renewable energy generation
To promote distributed generation of electricity
To reduce demand on central transmission grids
To reward early investment in renewable technologies
To facilitate energy self-reliance

Yet, even where states have adopted similar net metering statutes, no two states share the exact same regulations or procedures governing how the programs are implemented and monitored. In an effort to appease utility concerns about lost revenues, some state legislators have adopted statutory language that intentionally limits participation in net metering programs. In other states, well-intentioned state legislators have been thwarted by the addition of burdensome requirements and fees inserted at the regulatory level. In either case, these common barriers to participation are universally unnecessary and generally counterproductive.

Restrictions on Eligibility

Some state net metering rules restrict the customer classes that are eligible to participate in the program, often excluding commercial customers who may have the most substantial effect on reducing demand on the central transmission grid.[21] Since these customer classes typically consume more power than residential customers, they are also more likely to view net metering as an economic incentive to invest in on-site generation.

Most net metering programs are intended to encourage investment in technologies that are being delayed by market barriers. Restricting customer classes is often counterproductive to this goal. The Texas State Energy Conservation Office has noted, "It would make more sense to limit the eligibility of a technology for a period of time, say five or ten years, in order to give the technology a period in which it has the opportunity to become commercially viable, than to limit the size of the initial market, when the goal is creating a critical mass of market demand."[22]

Allowing commercial and industrial classes to be eligible for net metering is essential to jump-starting new renewable energy markets and reducing electricity demand.

21 Indiana, for example, allows only schools and residential customers to participate in the state's net metering program.

22 Texas State Energy Conservation Office. (2002) An Analysis Working Paper on Net Metering as an Incentive for Fuel Cell Applications, September 10. http://www.seco.cpa.state.tx.us/zzz_fuelcell-initiative/fclac_incen_netmeter.pdf

carries this credit forward to subsequent billing periods either throughout the year or indefinitely. Some of the least effective state net metering programs do not allow customers to bank excess generation, granting the utility excess electricity generated during a given monthly billing cycle. Other states limit the time that excess generation can be applied to future electricity bills.

Restrictions on banking are more a function of utility billing cycles than a rational public policy. Just because utilities bill on a monthly cycle does not mean that customers generating excess electricity for the grid should not be adequately compensated for the electricity they contribute to the grid. Compensation for excess generation encourages customers to participate in net metering programs and install systems that generate more renewable energy than is consumed on-site.[29] Utilities also benefit from banking because they do not incur the administrative costs associated with paying for small amounts of excess generation on a monthly basis. To be successful, a net metering program must facilitate banking so that customer-generators can receive credit for excess energy generated during the seasons when renewable output is highest and apply it toward their consumption when output is lower.

Total Program Capacity Limits

In a nod to utility concerns that on-site generation represents lost revenues, half of the states have limited the total capacity of electricity that is eligible for net metering. In most cases, the utilities are only required to honor net metering arrangements until the total amount of renewable energy generated by net metered customers reaches a certain percentage of the utility's aggregate peak demand. Generally, states have set capacity limits well below one percent of aggregate peak demand. In a majority of states, the limits are well below one half of one percent.[30] Once the total capacity of eligible net metered systems reaches the limit, the utility is no longer legally obligated to offer net metering to new customers.

It makes little sense to limit the total amount of clean energy that customers may generate and contribute to the electricity grid. Utilities do not have a divine right to charge for electricity that customers can otherwise generate more efficiently and more cleanly on their own. Capacity limits artificially restrict the expansion of on-site renewable generation and curtail the market for new renewable energy distributed generation (DG) systems.[31]

Utilities do not have a divine right to charge for electricity that customers can otherwise generate more efficiently and more cleanly on their own.

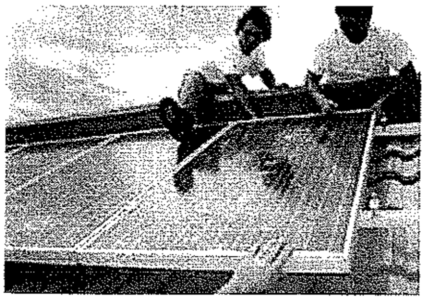
Capacity limits also create uncertainty for new customers considering net metering. Since customers have no way of knowing when capacity limits will be met, they cannot effectively plan for future DG installations and know for sure that those installations will qualify for net metering.[32] This regulatory uncertainty complicates calculations of buyback periods on capital investments and inhibits renewable energy services companies from providing accurate long-term cost projections to potential investors.

29 Hemrin, Jan, Dan Lieberman, and Meredith Wingate. (2006) Regulators Handbook on Renewable Energy Programs and Tariffs. Center for Resource Solutions. Page 52. March. http://www.resource-solutions.org/policy/TariffHandbook/Handbook_on_Renewable_Energy_Programs_&_Tariffs.pdf

30 DSIRE. 2006. www.dsireusa.org

31 California Energy Commission. (2004) Integrated Energy Policy Report 2004 Update. http://www.energy.ca.gov/reports/CEC-100-2004-006/CEC-100-2004-006CMF.PDF

32 Pacific Gas and Electric Company, Generator Interconnection Services Department. (2006) Pacific Gas and Electric Company's Position on the Net Energy Metering Enrollment Cap http://www.pge.com/suppliers_purchasing/new_generator/solar_wind_generators/nem_enrollment_cap.html



California

Caps can be counterproductive

California amended its net metering statute in 2002. The original law required utilities to provide net metering to customers until the total energy generated by net metering met 0.5% of the utility's aggregate peak demand. The state adopted this cap as a concession to utility companies, and justified it "due to the unknown impacts of increased customer-owned generation on the grid, particularly after the maximum capacity size was increased from 10 KW to 1 MW" in 2002.[33] By June 2006, the three major California utility companies (PG&E, SCE and SDG&E) were all close to reaching this cap, and some experts estimated the generation from net metered customers would likely exceed the cap before the end of the year.

33 California Public Utilities Commission Energy Division. (2005) Update on Determining the Costs and Benefits of California's Net Metering Program as Required by Assembly Bill 58. California Public Utilities Commission Energy Division. March 29. http://www.cpuc.ca.gov/WORD_PDF/REPORT/45134.PDF

If the aggregate number of customers happens to reach the maximum enrollment, the utilities would have no longer been required to offer customers net metering. At the time, many in the solar industry feared that there would be a significant decrease in demand for PV systems.[34, 35]

In partial response to the enrollment cap conundrum, in August 2006, California's state government passed SB1, the Million Solar Roofs Bill. This bill raised the enrollment cap to 2.5% of a utility's aggregate peak demand and provided additional funding for solar programs.

34 [illegible], Leah. (2006) California Nears Net Metering Cap. United Press International. June 5. http://[illegible].org/solarnews.php?id=115

35 Pearson, Ace. (2006) It's Nearly Lights Out for PG&E's Solar Power Paybacks. RenewableEnergyAccess. June 9. http://www.renewableenergyaccess.com/rea/news/story?id=45118

Discriminatory Standby Charges

Many utilities claim that, in the event that net metered systems fail, the utility is required to meet the resulting customer demand. As a result, many states allow utilities to impose a stand-by fee on net metered customers that is intended to cover the cost of the electricity the utility would otherwise be required to generate should the system fail.

The logic behind standby charges strains credulity. Some researchers have noted that they are "analogous to assigning standby fees to residential customers who purchase high efficiency air conditioning units."[36]

In some cases, standby charges are equal to or even exceed rates for full electrical service, in effect creating an economic disincentive for customers to install renewable energy DG systems. Indeed, in states where utilities have imposed these charges, the number of grid-tied solar PV installations has tended to decrease.[37]

Standby charges are particularly burdensome to small generators. Utilities only need to provide a negligible amount of back-up power for these customers. Yet standby fees may be so exorbitant that they diminish most, if not all, of the economic incentive net metering was intended to offer smaller generators. As well, when standby charges are levied, smaller generators, without leverage to negotiate a more reasonable rate with the utilities, are placed at a disadvantage to larger generators who may have more leverage with the utilities or more resources to devote to negotiating.[38]

36 Wenger, Howard, Tom Hoff, and Jan Pepper. (1996) Photovoltaic Economics and Markets: The Sacramento Municipal Utility District as a Case Study. California Energy Commission. September. http://www.energy.ca.gov/papers/1996-09_SMUD_SOLAR_STUDY.PDF

37 Alderfer, R. Brent, M. Monika Eldridge, and Thomas J. Starrs. (2000) Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects. National Renewable Energy Laboratory. July. http://www.nrel.gov/docs/fy00osti/28053.pdf

38 Larsen, Chris and Chris Cook. (2004) Connecting to the Grid: A Guide To Distributed Generation Interconnection Issues, Fourth Edition. Interstate Renewable Energy Council (IREC) and North Carolina Solar Center. http://www.[illegible].org/pdf/guide.pdf

Unreasonable Safety Requirements

In theory, net metered systems present a safety hazard if the central grid either shuts down or loses power but the interconnected systems continue to produce power without the utility's knowledge (a situation utilities call "islanding"). Potentially, line workers could come in contact with an unexpectedly energized line. Many utilities site these safety concerns to require that net metered customers install and test external shut-off switches on any interconnected system. However, the practical effect is that, like hidden interconnection fees, requiring additional external shut-off switches only adds unnecessary costs and discourages customers from investing in renewable energy systems.[39]

It is important to note that not one accident resulting from the "islanding" of net metered renewable energy systems has ever been reported in the United States.[40] More importantly, utility workers are trained to treat all lines as live and a variety of other safety precautions are required as part of standard operating procedures of line workers.[41] An external shut-off switch represents a 4th or 5th level of redundancy that is only relevant if a utility worker ignores his or her training and does not act according to protocol. If a worker is following proper protocol, none of the levels of safety preceding an external disconnect switch will ever be needed, much less the switch itself.[42]

Requiring additional external shut-off switches is also unnecessary since all inverters that meet Institute of Electrical and Electronics Engineers standards (IEEE1547) have automatic shut-off capabilities integrated with the systems.[43] All modern inverters, for example, shut down interconnected systems automatically in the event of grid failure.[44]

As well, recent studies have found that requiring additional, expensive safety equipment for net metered installations may inadvertently decrease worker safety by encouraging illegal interconnections or by forcing line workers to traverse customer property to access equipment (see page 77).

Unnecessary Insurance and Indemnification Requirements

Because of potential personal injury and property damage liability risks associated with interconnection of net metering systems, most state commissions allow utilities to impose additional, and often excessive, liability insurance requirements on net metered customers. Several utilities have required customer-generators to carry comprehensive general liability policies with one hundred thousand dollars or more in coverage to protect utilities from being held financially responsible for problems caused by interconnecting net metered systems. A limited number of states have enacted regulatory limits on the amount of additional insurance a utility may impose on a customer, and a few states prohibit utilities from imposing any additional insurance requirements for net metering.

39 Cook, Christopher. (no date) Interconnected PV - The Utility Accessible External Disconnect Switch. www.e3energy.com/Extdisc.doc

40 Xu, et al. (2004) An Assessment of Distributed Generation Islanding Detection Methods and Issues for Canada. CANMET Energy Technology Centre - Varennes, Natural Resources Canada. Report #CETC-Varennes 2004-074(TR)

41 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

42 Cook, Christopher. (no date) Interconnected PV - The Utility Accessible External Disconnect Switch. www.e3energy.com/Extdisc.doc

43 Institute of Electrical and Electronics Engineers (IEEE). (2003) 1547-2003 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems.

44 Larson, Chris and Chris Cook. (2004) Connecting to the Grid: A Guide To Distributed Generation Interconnection Issues, Fourth Edition. Interstate Renewable Energy Council (IREC) and North Carolina Solar Center. http://www.irecusa.org/pdf/guide.pdf

There has never been a documented case of a small-scale net metered system causing grid failure or creating potential personal injury or property damage liabilities for a utility.[45] Renewable energy technologies manufactured and installed in compliance with national interconnection standards significantly reduces the risk of potential safety issues and electrical failure problems.[46] Furthermore, product liability insurance carried by equipment manufacturers as well as the ability of these manufacturers to indemnify customers or utilities from liability for product failures negates the need for additional insurance.[47]

Excessive insurance requirements may also provoke customers to interconnect without informing the utility, which, as one utility executive noted, "will create safety problems in the name of safety."

Excessive insurance requirements only serve to discourage customers from investing in renewable energy systems and participating in net metering programs. Requiring customer-generators to obtain and maintain million-dollar insurance policies is impractical because the high premiums associated with these policies will likely exceed the economic benefits of participating in net metering programs. For example, a Florida utility imposed a $1 million insurance policy with an annual premium of $6200 that effectively shut down a commercial photovoltaic installation entirely.[48]

Excessive insurance requirements may also provoke customers to interconnect without informing the utility, which, as one U.S. utility executive stated, "will create safety problems in the name of safety."[49]

Lack of Public Awareness

Because many utilities view net metering requirements as revenue losers, they do not readily promote their programs.[50] Most state net metering statutes do not include any public information requirements. As a result, many customers remain unaware of the opportunities and benefits associated with investing in net metered systems.

In some cases, lack of promotion may limit participation even more directly. Building code officials unfamiliar with renewable energy technologies or state net metering regulations may add unnecessary permitting requirements that delay or discourage installations.[51] States should do a better job of promoting their net metering programs either by inserting public information requirements in their statutes or by directing state agencies to initiate public information efforts and fully funding their campaigns.

45 Starrs, Thomas J. (no date) Barriers and Solutions to Interconnection Issues for Solar Photovoltaic Systems. Prepared for the Solar Electric Power Association. http://www.resourcesaver.com/file/toolmanager/063F14189.pdf

46 Ibid.

47 Starrs, Thomas J. and Robert K. Harmon. (2000) Allocating Risks: An Analysis of Insurance Requirements for Small-Scale PV Systems. http://www.millionsolarroofs.org/articles/static/1/binaries/Allocating_Risks_Analysis_of_Insurance_Requirements_for_Small_Scale_PV_Systems.pdf

48 Alderfer, R. Brent, M. Monika Eldridge, and Thomas J. Starrs. (2000) Making Connections: Case Studies of Interconnection Barriers and their Impact on Distributed Power Projects. National Renewable Energy Laboratory. July. http://www.nrel.gov/docs/fy00osti/28053.pdf

49 Starrs, Thomas J. and Robert K. Harmon. (2000) Allocating Risks: An Analysis of Insurance Requirements for Small-Scale PV Systems. http://www.millionsolarroofs.org/articles/static/1/binaries/Allocating_Risks_Analysis_of_Insurance_Requirements_for_Small_Scale_PV_Systems.pdf

50 Wan, Yih-huei and H. James Green. (1998) Current Experience with Net Metering Programs. Green Power Network Online Report. http://www.eere.energy.gov/greenpower/resources/pdfs/current_nm.pdf

51 Starrs, Thomas J. and Howard J. Wenger. (1998) Promoting Profitable Home Power. Home Energy Magazine. http://www.homeenergy.org/archive/hem.dis.anl.gov/eehem/98/980111.html.

000305

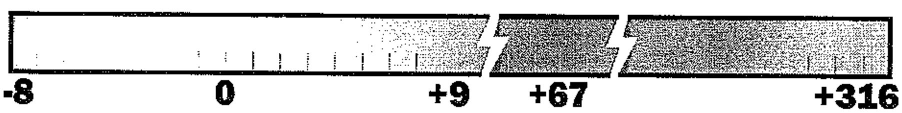
To measure the effectiveness of 34 statewide net metering programs[52], we developed an index that rewards program elements that promote participation, expand renewable energy generation or otherwise advance the goals sought by net metering.

Conversely, the index assigns demerits to program components that discourage participation, limit renewable energy generation or otherwise retard the goals sought by net metering programs.

We limited our analysis to statewide net metering programs. In many cases, these programs require that multiple utilities comply with the same set of state net metering rules. In Arizona, Florida, Idaho, and Illinois, utilities operate voluntary net metering programs. Since these programs are self-imposed and limited to certain parts of the state, we did not include them in our analysis.[52 53]

We measured program components as well as their impacts and assigned numerical values to each. For example, a value of zero means that the program component offers little to no incentive for a customer to participate. Negative values represent factors that undermine the effectiveness of the net metering program. Positive values represent additional incentives that contribute to program effectiveness.

Applying these numerical values to program components allows us to plot the effectiveness of each state net metering program on a continuum ranging from -8 to +316, where:



-8: characterizes the program that most discourages the goals of net metering

0: characterizes a minimal net metering program, but one that does not strongly encourage or discourage program goals.

+316: characterizes the program that displays the most features that encourage the goals of net metering.

52 Rhode Island's net metering program was created through public utility commission order for Narragansett Electric, which make up 99% of the mainland electric sales. Rhode Island is included in our analysis because the mandated rules cover the majority of the state's customers.

53 We excluded Michigan, North Carolina, and Washington D.C. all of which began their program after 2004.

Measures of Program Effectiveness

Customer Participation – The number of customers enrolled in net metering programs indicates how effective the net metering policies are at creating incentives for participation. Effective programs should see progressively increasing numbers of participants. We compared the most recent, publicly available data from the U.S. Department of Energy, Energy Information Agency (EIA), which has surveyed the number of net metering participants in each state since 2002 and published data sets for 2002, 2003 and 2004.

To account for variable population densities, we translated raw participation numbers into the number of net metering customers per million utility customers within each state. This calculation allows us to more accurately compare the rate of growth in participation between states with widely varying populations.

-1: The number of participants declined

0: Fewer than 10 customers per million joined the program from 2002-2004.

↳ The states in this range were neutral or marginally better than neutral. We decided that single digit growth did not represent a positive/effective program.

1: 10 to 99 customers per million joined the program.

↳ Programs with participation levels in this range indicate that the program was marginally effective.

+1 point: We assigned one point for every additional 100 participants per million utility customers.

The Magic of 67

A cursory examination of raw participation numbers reveals that many states have few, if any, participating customers. We have examined why participation rates are so low in these states. However, low raw figures complicate any analysis of the change in participation rates over the limited time period for which data is available. For example, Utah registered not a single net metering customer in 2002, 1 customer in 2003, and 10 customers in 2004. A crude calculation of Utah's rate of participation would reveal a 1000 percent increase from 2002 to 2004. However, such a calculation would reflect an inaccurate assessment of the effectiveness of Utah's program.

To account for states with low participation rates, we performed a regression analysis that plots the age of a state's net metering program against the number of net metering participants per million utility customers (see Appendix A). The results of the regression analysis conclude that the age of a state's net metering program is not a significant factor in customer participation rates. We found that just because a program has been in place for several years, it does not mean that the number of customers participating in the program will have increased.

More importantly, our regression analysis reveals that the change in program participation from 2002 to 2004 is only a relevant calculation for states that have overall participation rates exceeding 67 net metering participants per million electricity customers. In states that have adopted net metering programs, our analysis shows that the expected rate of participation is 67 customers for every million electric utility customer, all other factors being equal. Therefore, we used 67 participants as a "floor" for factoring the change in net metering participation as a measure of program effectiveness. For states with less than 67 program participants per million utility customers, we ignored any growth in participation rates from 2002 to 2004, since any changes are below what is expected in any case. For states with participation rates exceeding 67 net metering participants per million utility customers, we calculated the percent change from 2002 to 2004 and rewarded any growth accordingly.

0: <67 Customers

↳ Less than 67 participants per million customers indicates that the net metering program was ineffective.

1: 0 to 99% Growth

↳ For states having more than 67 net metering participants per million utility customers, we assigned one point for any growth in participation rates from 2002-2004.

+1 point: Every 100% increase in growth

↳ States earned one point for every additional 100% increase in their state's participation rate. For example, Nevada experienced 236% growth from 2002 to 2004. Therefore, the state scored 3 points: 1 point for growth from 0 to 99%, 1 point for the next increment of growth (100% to 199%), and 1 point for next increment of growth (200% to 300%).

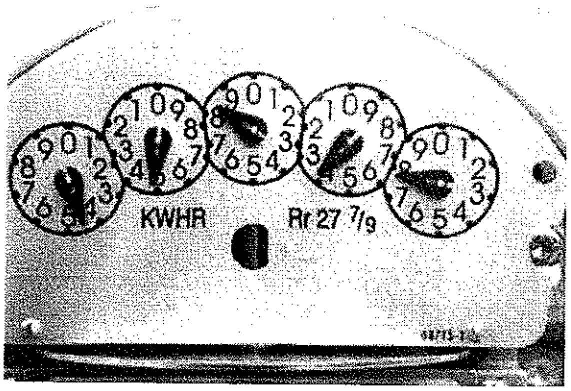
System Size Limits (residential) – Residential electricity loads generally range between 2kW and 4kW. State net metering programs that allow residential systems above 10kW create incentives for excess generation for almost all residential customers. We used the following values to assess residential system size limits:

-1: Net metering regulations limited renewable generators to less than 2kW in overall capacity. Limits this low will not allow customer-generators to produce enough electricity to cover their entire on-site demand.

0: Net metering regulations allowed for renewable generators from 2 to 10kW in overall capacity.

1: Net metering regulations allowed for renewable generators in excess of 10kW in overall capacity.

System Size System (non-residential) – Non-residential loads tend to be larger than residential. To be as inclusive as possible for all non-residential customer loads, system size limits should be large enough to exceed the on-site demand of most commercial operations. We used the following values to assess non-residential system size limits:



-1: Net metering regulations limited renewable generators to less than 25kW in overall capacity. Limits this low will alienate larger customer classes from producing a substantial portion of their load with on-site renewable generation.

0: Net metering regulations allowed for renewable generators from 25 to 149kW in overall capacity. This range will cover most commercial classes, but still may be too small for most industrial loads.

1: Net metering regulations allowed for renewable generators from 150 to 999kW in overall capacity. Renewable energy systems in this range should cover a majority of non-residential classes.

2: Net metering regulations allowed for renewable generators in excess of 1000kW in overall capacity. Above the 1000kW threshold, nearly all loads will exceed on-site demand, allowing commercial and industrial customers to take advantage of any incentives for net excess generation.

Interconnection Standards – Without interconnection standards determined by statute, utilities can charge high interconnection fees and delay the installation process with long and complicated rules and procedures. In 2005, the Federal Energy Regulatory Commission (FERC) issued uniform interconnection standards for small generators and required all public utilities that own, control or operate interstate electricity transmission lines to comply with them. However, since our analysis looks specifically at the effectiveness of state program prior to 2005, we included an assessment of interconnection standards and assigned the following numerical values:

-2: The state had not adopted a standard or the standard varied by utility and was not determined by statute – OR – Interconnection rules were left to the utility's discretion.

-1: The state was developing a standard, but no statewide standard existed by 2004.

0: The state had adopted a practical and reasonable standardized process for application and approval.

Treatment of Net Excess Generation (NEG) – Compensation for net excess generation provides a powerful economic incentive to invest in on-site renewable energy systems and helps offset the capital costs associated with interconnection. We assigned the following values based on how the net metering program credits NEG.

-3: NEG was gifted to the utility on a monthly basis

↳ This situation denies the customer any way of banking excess generation and applying the credit to the next billing cycle. Monthly gifting does not account for the seasonal variability of renewable generation. If a customer-generator wants to be energy self-reliant, they must size their system to the season of least energy generation, but lose the value of any excess energy produced during seasons when generation is greatest.

-2: NEG was sold to the utility at the avoided cost on a monthly basis

↳ While crediting monthly excess generation at the avoided cost creates some financial incentive for production, it presents similar problems associated with season variability and allows the utility to pocket the profits from selling NEG to other customers at the retail rate.

-1: NEG was sold to the utility at the retail rate on a monthly basis

↳ Close in financial terms to month-to-month banking, this situation would have the utility incur additional administrative costs associated with purchasing small amounts of electricity on a monthly basis. Currently, no state programs require utilities to purchase NEG at the retail rate on a monthly basis.

0: Excess generation was granted to the utility at the end of an annual billing cycle.

↳ A minimally satisfactory net metering program will allow the customer-generator to install a DG system that will provide enough electricity for on-site demand. Gifting NEG to the utility on an annual basis allows the customer to take advantage of month-to-month banking, but does not provide a mechanism to compensate customers for any generation exceeding annual on-site demand.

1: NEG was purchased by the utility at the utility's avoided cost on a yearly basis.

↳ This situation creates an incentive for customers to install renewable energy systems large enough to generate more energy than they consume and gives consideration to the seasonal variability of renewable energy generation.

2: NEG was purchased by the utility at the retail rate on an annual basis or carried over at the retail rate indefinitely.

↳ Purchasing NEG at the retail creates a larger economic incentive for customers to invest in renewable energy systems that exceed on-site demand and ensures that any profit from selling the excess generation is passed on to the renewable generator.

Total Capacity Limits - Capacity limits stunt the growth of renewable energy DG systems by artificially limiting the number of systems that are eligible for net metering benefits. We assigned numeric values to total capacity limits as such:

0: Net metering regulations prohibit total capacity from exceeding a certain percentage of peak load.

1: Net metering regulations do not include maximum capacity limits.

Additional Installations – Extraneous devices add to the cost of a renewable energy DG system, creating a financial disincentive for participation. We assigned the following values to regulations requiring additional installations:

-1: Individual utilities determine if additional installations (such as mandatory external shut-off switches) are required and whether the customer bears the cost.

0: Customers are not required to purchase or install additional devices.

Liability Insurance Requirements – Requiring additional insurance for net metered renewable energy DG systems can make the systems prohibitively expensive. We assigned the following values to liability insurance requirements:

-1: Additional liability insurance is required of all net metering participants or is otherwise left to the discretion of the utility.

0: Customers are not required to purchase additional liability insurance.

Chart 3.1: Overview of State Net Metering Programs in 2004[55]

State	Arkansas	California	Colorado*	Connecticut†	Delaware	Georgia
[illegible]	F-	A	F	C	F	C
Rank	31	3	26	15	25	18
Number of net metering customers per million (2003)	2	1101	44	22	0	1
Change in the number of net metering customers per million 2002-2004	0%[56]	435%	0%	0%	0%	0%
Limit on total capacity	None	0.5% of a utility's peak	None	None	None	0.2% of a utility's annual peak demand
Eligible technologies	Solar, Wind, Hydro, Biomass, Fuel Cells, Geothermal, Microturbines	Solar PV, Wind, Anaerobic Digestion, Landfill Gas, Fuel Cells	Solar, Wind, Biomass, Small Hydro, Landfill Gas, Anaerobic Digestion, Fuel Cells (Renewable)	Solar, Landfill Gas, Wind, Biomass, Fuel Cells, Small Hydro, Tidal Energy, Wave Energy, Municipal Solid Waste, Ocean Thermal	Solar, Wind, Hydro, Biomass, Geothermal	PV, Wind, Fuel Cells
System Size Limit / Customer Class	25kW/Residential 100kW/Commercial	1MW/Commercial, Industrial, Residential	10kW / Commercial, Industrial, Residential	100 kW (renewable), 50kW (fossil)/ Residential, Commercial	25kW / Commercial, Residential	10kW / Residential. 100kW / Commercia
Treatment of Net Excess Generation (NEG)	Granted to Utility monthly	Credited at retail rate month-to-month; granted end of annual billing cycle	Credited at retail rate to next bill month-to-month	Purchased at avoided-cost at end of billing period	Varies by Utility	Credited at retail rate month-to-month; granted end of annual billing cycle
External Safety Switch Required?	Yes	Yes[57]	No	Yes	Yes	No
Additional Insurance Required?	No	No	No	Yes	Yes	No
Interconnection Standard	Yes	Yes	No	Yes	Yes	Yes

55 State net metering programs are represented as they appeared in 2004. Data from: DSIRE/IREC. 2006. www.desireusa.org , U. S. Dept. of Energy, Office of Energy Efficiency and Renewable Energy. July 12, 2004 http://www.eere.energy.gov/greenpower/pdfs/metering_0604.pdf . Union of Concerned Scientists. March 2003., Customer Data from U. S. Dept. of [illegible] Energy Information Agency

56 States with fewer than 67 customers per capita are not included in the growth rate column for reasons explained above.

57 Systems greater than 1 kW

* Indicates states that enacted state programs during or after 2002

† Indicates amendments or additions to program during or after 2002

State	Hawaii†	Indiana*	Iowa	Kentucky†	Louisiana*	Maine
Grade	B	F	F	D	B	D
Rank	**9**	**28**	**24**	**21**	**13**	**22**
Number of net metering customers per million (2004)	**118**	**6**	**6**	**1**	**0**	**0**
Change in the number of net metering customers per million, 2002-2004	**317%**	**0%**	**0%**	**0%**	**0%**	**0%**
Limit on total capacity	0.5% of a utility's annual peak demand	0.1% of a utility's most recent peak summer load	None	0.1% of a utility's single hour peak load during the previous year	None	None
Eligible Technology	Solar, Wind, Hydro, Biomass	PV, Wind, Small Hydro	PV, Wind, Hydro, Biomass, Municipal Solid Waste	PV	PV, Wind, Hydro, Biomass, Fuel Cells (Renewable), Geothermal, Microturbines	Solar, Wind, Biomass, Geothermal, CHP, Hydro, Fuel Cells, Municipal Solid Waste, Tidal Energy
System Size Limit / Customer class	50kW/Commercial, Industrial, Residential	10kW/Residential, Schools	500kW / Commercial, Industrial, Residential	15 kW / All Electric Customers	100kW / Commercial, Agricultural; 25 kW / Residential	100kW / Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Credited to utility at end of the month	Credited to customer's next bill indefinitely	Purchased at avoided monthly cost	Credit at retail rate to customer's next bill indefinitely	Credit at retail rate to customer's next bill indefinitely	Credited at retail rate to next bill; granted at end of annual billing cycle
External Shutoff Switch Required	**Yes**	**Yes**	**No**	**No**	**Yes**	**No**
Additional Insurance Required	**No**	**Yes**	**No**	**No**	**No**	**No**
Interconnection Standards	**Yes**	**No**	**No**	**No**[58]	**Yes**	**No**

58 Individual utilities have filed interconnection tariffs

C00309

* indicates [illegible] state programs during or after 2002

† indicates amendments or additions to program during or after 2002

State	Maryland†	Massachusetts	Minnesota	Montana	Nevada†	New Hampshire
Grade	F	F	A	A	A	A
Rank	29	23	6	2	5	7
Number of net metering customers per million (2004)	4	66	106	432	107	142
Change in the number of net metering customers per million 2002-2004	0%	0%	231%	5955%	236%	114%
Limit on total capacity	0.2% of state's adjusted peak load in 1998	None	None	None	1% peak capacity	0.05% peak capacity
Eligible technology	PV, Wind	Solar, Wind, Biomass, Municipal Solid Waste, CHP, Fuel Cells, Hydro	PV, Wind, Hydro, Biomass, Municipal Solid Waste, CHP	PV, Wind, Hydro	Solar, Wind, Biomass, Hydro, Geothermal	PV, Wind, Hydro
System size limit / Customer class	80kW / Commercial, Residential, Schools	60kW/Commercial, Industrial, Residential	40kW/ Commercial, Industrial, Residential	50kW / Commercial, Industrial, Residential	30 kW / Commercial, Industrial, Residential	25kW / Commercial, Industrial, Residential
Treatment of net excess generation (NEG)	Granted Monthly	Purchased at avoided monthly cost	Purchase at retail rate	Credited at retail rate to next bill; granted at end of annual billing cycle	Credit at retail rate to customer's next bill indefinitely	Credited at retail rate to customer's next bill
External Shutoff Switch Required	No	No	Yes	No	No	No[59]
Additional Insurance Required	No	No	Yes	No	No	No
Interconnection Standards	Yes	No	Yes	Yes	Yes	Yes

59 Yes, for systems larger that 10 kW

* indicates states that enacted new programs during or after 2002
† indicates amendments or additions to programs during or after 2002

State	New Jersey†	New Mexico	New York	North Dakota	Ohio	Oklahoma
Grade	A	C	C	F	B	F
Rank	1	17	16	27	12	34
Number of net metering customers per million (2004)	93	14	13	13	4	20
Change in the number of net metering customers per million 2004-2006	30,141%	0%	0%	0%	0%	0%
Limit on total capacity	0.1% peak capacity or $2 million annual impact	None	0.1% of 1996 demand in (solar), 0.4% of 1996 demand (farm biogas), 0.2% of 2003 demand (wind)	None	1% of a utility's peak demand	None
Eligible Technology	Solar, Wind, Biomass, Hydro, Geothermal, Tidal Energy, Fuel Cells (Renewable), Wave Energy	Solar, Wind, Biomass, Hydro, Municipal Solid Waste, Fuel Cells, CHP, Geothermal, Microturbines	PV, Wind, Biomass	Solar, Wind, Hydro, CHP, Geothermal, Biomass, Municipal Solid Waste	Solar, Wind, Hydro, Biomass, Fuel Cells, Microturbines	Solar, Wind, Hydro, Biomass, Geothermal, Municipal Solid Waste, CHP
System size limit / Customer class	100kW / Commercial, Residential	10kW / Commercial, Industrial, Residential	10kW (solar)/ Residential, Agricultural; 400kW (biogas) 125 kW (wind)/ Agricultural; 25 kW (wind)/ Residential	100kW/ Commercial, Industrial, Residential	No Limit, 100kW (microturbines)/ Commercial, Industrial, Residential	100 kW (up to 25,000 kWh/ year) / Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Credited at to next bill; purchased at avoided cost at end of annual billing cycle	Credited to next bill or purchased at avoided-cost at end of annual billing cycle	Credited to customer's next bill; purchased at avoided-cost at end of annual billing cycle.[61]	Purchase by utility at avoided-cost rate at the end of a monthly billing period	Credited at utility's unbundled-generation rate to customer's next monthly bill	Granted to utility monthly or credited to next bill at avoided-cost; utility's choice
External Safety Switch Required	No	Yes	Yes	Yes	No[62]	No
Additional Insurance Required	No	No[60]	No	Yes	No	No
Interconnection Standards	Yes	No	Yes	Yes	Yes	Yes

60 Public Regulation Commission may require insurance
61 Wind >10 kW credited month-to-month at avoided-cost
62 Utilities may require an external disconnect switch

000310

State	Oklahoma	Oregon†	Pennsylvania†	Rhode Island	Texas	Utah*
Grade	F	A	F	F	F	B
Rank	**34**	**4**	**33**	**32**	**30**	**14**
Number of net metering customers per million (2004)	**20**	**152**	**17**	**59**	**72**	**12**
Change in the number of net metering customers per million 2002-2004	**0%**	**1019%**	**0%**	**0%**	**0%**	**0%**
Limit on total capacity	None	0.05% of a utility's peak load	None	1 MW	None	0.1% of 2001 peak demand
Eligible Technology	Solar, Wind, Hydro, Biomass, Geothermal, Municipal Solid Waste, CHP	Solar, Wind, Hydro, Fuel Cells	Renewable energy including fuel cells	Solar, Wind, Hydro, Biomass, Geothermal, Fuel Cells, Municipal Solid Waste, CHP	Solar, Wind, Biomass, Hydro, Tidal, Wave, Geothermal, Fuel Cells, Microturbines	Solar, Wind, Fuel Cells, Hydro
System size limit / Customer class	100 kW (up to 25,000 kWh/ year) / Commercial, Industrial, Residential	25kW / Commercial, Industrial, Residential	10kW / All customer classes	25kW / Commercial, Industrial, Residential	50kW/Commercial, Industrial, Residential	25kW/ Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Granted to utility monthly or credited to next bill at avoided-cost; utility's choice	Credited at retail rate to customer's next bill or purchased by utility at avoided-cost rate	Granted Monthly	Granted to utility monthly	Purchased by utility monthly at avoided-cost rate	Credited to next bill; granted at end of annual billing cycle
External Shutoff Switch Required	**No**	**No**	**No**	**No**	**Yes**	**No**
Additional Insurance Required	**No**	**No**	**No**	**No**	**No**	**No**
Interconnection Standards	**No**	**Yes**	**No**	**No**	**Yes**	**Yes**

* Indicates states that enacted state programs during or after 2002

† Indicates amendment or additions to program during or after 2002

State	Vermont†	Virginia†	Washington	Wisconsin	Wyoming
Grade	B	D	D	A	B
Rank	**10**	**20**	**19**	**8**	**11**
Number of net metering customers per million 2004	**226**	**6**	**28**	**85**	**47**
Change in the number of net metering customers per million 2002-2004	**152%**	**0%**	**0%**	**127%**	**0%**
Limit on total capacity	1% of peak demand of 1996 or recent year	0.1% of annual peak demand	0.25% of a utility's 1996 peak load	None	None
Eligible Technology	PV, Wind, Biomass, Fuel Cells	Solar, Wind, Hydro	Solar, Wind, Hydro,Biogas, Fuel Cells, CHP	Solar, Wind, Biomass, Hydro, Geothermal, CHP, Municipal Solid Waste	Solar, Wind, Biomass, Hydro,
System size limit / Customer Class	150kW / Agricultural 15kW / Commercial, Residential	500 kW / Non-residential 10 kW / Residential	25kW / Commercial, Industrial, Residential	20kW / Commercial, Industrial, Residential	25kW / Commercial, Industrial, Residential
Treatment of Net Excess Generation (NEG)	Credited at retail rate to next bill; granted at end of annual billing cycle	Credited to next bill; granted at end of annual billing cycle	Credited to next bill; granted at end of annual billing cycle	Renewable energy purchased by utility at retail rate / Non-renewable at avoided-cost rate	Credited to next bill; purchased at avoided-cost rate at end of annual billing cycle
External Switch Required	**Yes**	**Yes**	**No**	**Yes**	**Yes**
Additional Insurance Required	**Yes**	**Yes**	**No**	**Yes**	**No**
Interconnection Standards	**Yes**	**Yes**	**No**	**Yes**	**Yes**

000311

* Indicates states that enacted state programs during or after 2002
† Indicates amendments or additions to program during or after 2002

Grading the States

We assigned a grade to each state's net metering program by ranking the state's based on their index score and then calculating a percentile based on the highest-ranked state (New Jersey) representing 100 percent (an A).

Since an index score of zero should represent a minimally satisfactory net metering program, we assigned states with index scores of 0 the grade of "D" or just passing. Our calculation roughly translates as >75th percentile = A, 55th-74th percentile = B, 40th-54th percentile = C, 30th-44th percentile = D, and <30th percentile = F. Chart 3.2 displays each state's index score, percentile, and grade.

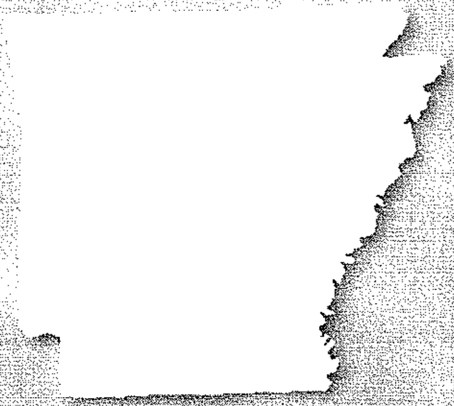
Although many of the 34 state net metering rules are similar, each has its idiosyncrasies. After we used the index system to create a way of generalizing effective versus ineffective net metering rules, we compared individual state programs with the same index score and made more specific evaluations to break ties (see Appendix B). We ranked states that had the greatest customer growth and highest overall participation higher than other states.[54]

54 Our justification for weighting certain program components as more important than others is primarily a reflection of customer participation. The primary indicator for an effective program is participation. Additional ranking factors are explained in our comparison of 'worst practices' in Arkansas and Indiana. By comparing the affect of different program components on participation rates in each state, for example, we deduced that the treatment of net excess generation had a more significant impact than total capacity limits.

CHART 3.2: GRADING STATE NET METERING PROGRAMS

Rank	State	Grade	Percentile	Score
1	New Jersey	A	100%	305
2	Montana	A	97%	67
3	California	A	94%	15
4	Oregon	A	91%	14
5	Nevada	A	88%	7
6	Minnesota	A	82%	6
7	New Hampshire	A	82%	6
8	Wisconsin	A	79%	4
9	Hawaii	B	64%	3
10	Vermont	B	64%	3
11	Wyoming	B	64%	3
12	Ohio	B	64%	3
13	Louisiana	B	64%	3
14	Utah	B	61%	2
15	Connecticut	C	48%	1
16	New York	C	48%	1
17	New Mexico	C	48%	1
18	Georgia	C	48%	1
19	Washington	D	36%	0
20	Virginia	D	36%	0
21	Kentucky	D	36%	0
22	Maine	D	36%	0
23	Massachusetts	F	27%	-1
24	Iowa	F	27%	-1
25	Delaware	F	27%	-1
26	Colorado	F	9%	-2
27	North Dakota	F	9%	-2
28	Indiana	F	9%	-2
29	Maryland	F	9%	-2
30	Texas	F	9%	-2
31	Arkansas	F	9%	-2
32	Rhode Island	F	3%	-3
33	Pennsylvania	F	3%	-3
34	Oklahoma	F	0%	-4

Arkansas



F

Number of customers 2004	**3**
Change per million customers (2002- 2004)	**0%***
System size limit	**25 kW for residential systems; 100kW for commercial systems**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Granted to utility monthly**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Biomass, Fuel Cells, Geothermal Electric, Microturbines using renewable fuels**
External shut-off	**Yes**
Additional insurance	**Utility discretion**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

On April 19, 2001, Arkansas Governor Mike Huckabee signed into law a bill (HB 2325) requiring the state's electric utilities to offer net metering for solar, wind, hydroelectric, geothermal, and biomass systems. In addition, fuel cells and micro turbines are required to be fueled by renewable sources. The Arkansas Public Service Commission (APSC) approved final net-metering rules in July 2002.

The APSC allows residential systems up to 25 kilowatts (kW) and commercial systems up to 100 kW to be eligible for net metering. There is no total capacity cap, however, APSC Order No. 02-046-R states that any net excess generation (NEG) will be credited to the utility at the end of the billing period without any compensation to the customer. Utilities are granted the discretion to charge interconnection fees and require customers to install external disconnect switches. Utilities may also require additional liability insurance up to $1 million.

Developments since 2004: In July, 2006 the APSC began its consideration of the state's net metering rules pursuant to EPAct and designated all of the state's regulated utilities as official parties to the proceedings. All other parties had to petition to intervene by August 25, 2006. Only two additional non-utility interveners (a consumer group and a renewable energy service provider) were granted permission to submit comments.

Recommendations:
- Amend official docket procedures to allow open public comment periods on Commission rulemakings
- Allow monthly banking of net excess generation, purchased annually at the retail rate
- Allow systems up to 2MW to be eligible for net metering
- Remove utility discretion to charge interconnection fees, require external shutoff switches and additional liability insurance.

California

A

Number of customers 2004	**13,506**
Change per million customers (2002- 2004)	**435%***
System size limit	**1 MW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate month-to-month; granted end of annual billing cycle**
Limits on enrollment	**0.5% of a utility's peak**
Eligible technologies	**Solar PV, Wind, Anaerobic Digestion, Landfill Gas, Fuel Cells**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities (solar and wind); Investor-owned utilities (biogas and fuel cells)**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page X).

California's net metering law took effect in 1996. All utilities must permit net metering for solar, hybrid, and wind-energy systems with a capacity limit of 1 MW; investor owned-utilities must also allow net metering for biogas-electric systems and fuel cells. Significant amendments were made in 2002 under AB 2228, notably relating to biogas systems, fee structures, and system size limits for wind energy projects.

Developments since 2004: In September 2005, AB 728 further extended eligibility requirements for biogas-powered systems. Authored by Senator Kevin Murray, SB 1 was unanimously approved on August 8, 2006 by the California Senate Energy, Utilities and Communications Committee as a net metering bill which raises the cap on investor-owned utilities' load from 0.5% to 2.5%. Rep. John Campbell (R) and Senator Dianne Feinstein (D) also advocated for the new legislation. The bill supports the California Solar Initiative, which has a goal of installing 3,000 MW solar systems by 2017, and has been applauded by solar advocates as a step towards making the Solar Initiative program economically feasible for participants.[64]

Recommendations:
- Remove limits on aggregate enrollment
- Increase system-size limit to at least 2 MW
- Remove requirements for external disconnect switch

64 Electric Power Daily, August 9, 2006.

Colorado

F

Number of customers 2004	**87**
Change per million customers (2002- 2004)	**0%***
System size limit	**10 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate to next bill month-to-month**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Biomass, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utility**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Because our data set was limited to publicly available data on net metering customer participation from 2002-2004, Colorado's grade and ranking reflect the lackluster net metering program put in place by the Colorado Public Utilities Commission (CPUC) prior to 2004.

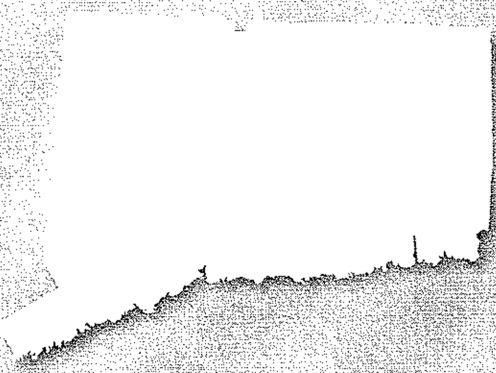
Developments since 2004: In November 2004, Colorado became the first state in history to put a renewable energy portfolio (RPS) up for a vote rather than go through the state's legislature. After failing four times in the legislature, 52% of Colorado voters approved Amendment 37, requiring a 10% renewable energy generation by 2015 and establishing statewide net metering rules.

In December 2005, after extensive meetings with many renewable energy interest groups, the CPUC issued an order adopting implementation rules for Amendment 37. The CPUC now allows systems up to two megawatts (MW) in capacity to be eligible for net metering. Electricity generated at a customer's site can be applied toward meeting the utility's renewable generation requirement. Colorado's RPS requires that 4% of the requirement be met with solar energy, half of which must come from customer-generators.

Net excess generation (NEG) is credited to the following month's billing cycle. At the end of an annual billing cycle, the utility must reimburse the customer for the excess generation at the utility's average hourly incremental cost for the prior 12-month period. Systems over 10 kilowatts (kW) in capacity require a second meter to measure output that counts toward renewable-energy credits (RECs). Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity.

Applying NNEC's metric to the program adopted in 2005, Colorado would rank in the top 5 statewide net metering programs and receive an A rating!

Connecticut



C

Number of customers 2004	**31**
Change per million customers (2002- 2004)	**0%***
System size limit	**100 kW (renewable), 50kW (fossil)**
Eligible classes	**Commercial, Residential, Multi-Family Residential**
Net excess generation	**Purchased at avoided-cost at end of billing period**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Fuel Cells, Municipal Solid Waste, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Connecticut first implemented net metering legislation in 1990, under the DPUC (Connecticut Department of Public Utility Control) Ruling 159. With this ruling, utilities had to purchase NEG from qualifying facilities with a maximum capacity of 50 kW non-renewable energy systems, and 100 kW for renewable-energy systems. Following the electric restructuring bill of 1998, all investor-owned utilities were required to offer net metering to customer-generators using renewable energy sources, including solar, wind, hydropower, landfill gas, fuel cells, and/or sustainable biomass.[65] In June 2003, amendments were enacted to include wave and tidal energy sources and decreased monetary restrictions for units less than 10kw.[66] Though distribution companies are only required to offer net metering to residential customers, Connecticut Light & Power Company (CL&P) and United Illuminating Company (UI) provide net metering to commercial entities that meet certain conditions.[67]

Developments since 2004: In May 2006, renewable energy proponents tried to pass SB 211, which would have increased kilowatt limits and the carryover billing period,[68] however the bill was stalled in the Senate.[69]

Recommendations:

- Include industrial as part of eligible customer classes
- Increase system-size limits to at least 2MW
- Amend treatment of net excess generation to be purchased at retail rate at end of annual billing cycle
- Exclude any external shutoff switch or additional insurance requirements

65 "Connecticut Incentives for Renewables and Efficiency." DSIRE Database of State Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=CT01R&state=CT&CurrentPageID=1&RE=1&EE=1.

66 Issue: Net Metering. State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html

67 Ibid

68 Filler, Stephen. 2006. Net Metering Bill in CT Needs Help. Green Counsel Blog: State and Local Government. 5 May 2006. http://nylawline.typepad.com/greencounsel/state_and_local_government/index.html

69 Substitute Bill No. 211. http://www.cga.ct.gov/asp/cgabillstatus/cgabillstatus.asp?selBillType=Bill&bill_num=211&which_year=2006&SUBMIT.x=11&SUBMIT.y=0

000314

Delaware

D

Number of customers 2004	**0**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Residential**
Net excess generation	**Varies by Utility**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Delaware adopted net metering legislation in 1999 under HB 10, the Electrical Restructuring Act. The act required that Conectiv (now Delmarva) and Delaware Electric Cooperative (DEC) offer net metering to residential and commercial customers with systems up to 25kW, with no limit on capacity for renewable energy.[70] Technical standards and treatment of net excess generation vary between these two utilities. However, the state's nine municipal utilities, which are not included in the act, have not adopted any net metering policies and consist of 30% of the Delaware consumer market.[71]

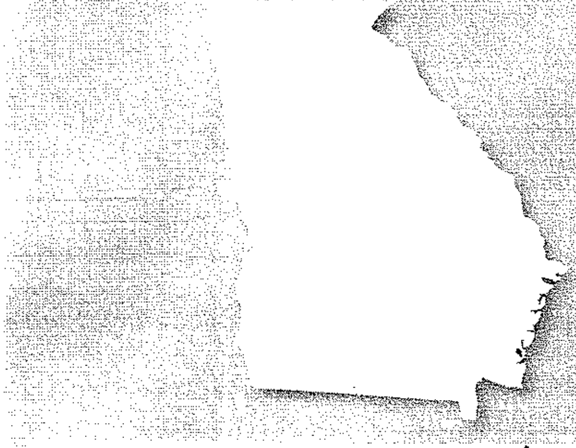
Recommendations:

- Include industrial in eligible customer classes
- Increase system size limit to at least 2MW
- Create a standard treatment of net excess generation in the state, to be credited at retail rate and carried over indefinitely
- Remove external shutoff switch and additional insurance requirements

70 "Delaware Incentives for Renewables and Efficiency" DSIRE:Database of State Incentives for Renewable Energy.<http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=DE02R&state=DE&CurrentPageID=1&RE=1&EE=1

71 Burton, Sandra A.H., Gallagher, Brian R., "Market Barriers to Grid-Interconnected Photovoltaics: A Survey of Delaware's Municipal Electric Utilities." Green Plains Energy, Inc. 12 Dec. 2003. http://www.greenplainsenergy.com/documents/DEMEC%20PV%20Barriers%20Study-12-12-03.pdf

Georgia



C

Number of customers 2004	**2**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW/ Residential, 100kW/ Commerical**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate month-to-month; granted end of annual billing cycle**
Limits on enrollment	**0.2% of a utility's annual peak demand**
Eligible technologies	**Photovoltaics, Wind, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Georgia's net metering rules went into effect under SB 93, the Cogeneration and Distributed Generation Act of 2001, which was a restructuring of Georgia's 1979 cogeneration law. The bill took about a month to move from a favorable review in Senate committee to the Governor.[72]

Georgia's legislation combines net metering with green pricing. The nonprofit Georgians for Clean Energy (GCE) worked closely with Georgia Power - a subsidiary of Southern Company - in the development of the law. Also supporting the law as it moved through the legislature were the Georgia Electric Membership Corporation, the Municipal Electric Authority of Georgia, and various environmental and consumer groups. However, Georgia Power and the state's other utilities have not yet established their green pricing program, and the green pricing tariffs still need to be filed.

Power flows to and from the home are separately measured. Customers are given a choice of metering arrangements: the customer's system can be interconnected on the customer side of the meter with a bi-directional meter to measure flows in each direction, or customers can send all of the power from their system directly to the grid.

Recommendations:

- Increase system-size limits to at least 2 MW
- Remove aggregate limit on enrollment
- Reimburse NEG to customer-generator at retail rate at end of 12-month period

72 Georgia General Assembly, 2001 SB 93 - Georgia Cogeneration and Net Metering Act; program for operators of solar electrical cogeneration. http://www.legis.ga.gov/legis/2001_02/sum/sb93.htm

000315

Hawaii

B

Number of customers 2004	**46**
Change per million customers (2002- 2004)	**317%***
System size limit	**50kW**
Eligible classes	**Commercial, Residential, Local Government, State Government, Fed. Government**
Net excess generation	**Credited to next month's bill; granted to utility at end of 12 month period**
Limits on enrollment	**0.5% of a utility's annual peak demand**
Eligible technologies	**Solar Photovoltaics, Wind, Biomass, Hydroelectric**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

As an island state without many energy resources, Hawaii is in a position that requires innovative energy solutions. Hawaiian officials have looked into a variety of energy options including renewable and waste-to-energy technologies. Even with those options, the state still relies on oil for nearly 80% of its electricity. Realizing this one-sided production, Rep. Hermina Morita, chairperson of the House Energy and Environmental Protection Committee, helped lead the way towards more renewable energy and energy efficiency.

In 2001, she helped House Bill 173 pass through the legislature. This bill created a state renewable portfolio standard and included net energy metering provisions to help promote distributed renewable energy systems.[73] The net metering provisions were revised in 2004 by HB 2048, expanding the system capacity limit from 10 kW to 50 kW.

Developments since 2004: In 2005, Hawaii's net metering law was again amended by HB 606, eliminating a provision allowing utilities to impose additional requirements on net-metered systems. In the same year, SB 1003 allowed the PUC to increase limits imposed in the 2001 rules, as well as permitted NEG to be carried over to subsequent bills.[74]

Recommendations:
- Increase system-size limits to at least 2 MW
- Remove limits on aggregate enrollment
- Remove requirements for external disconnect switch
- Credit all NEG at retail rate

73 Leone, Diana. June 10, 2001. Plugged in: Hawaii's quest for power boosts interest in renewable resources. Honolulu Star-Bulletin. http://starbulletin.com/2001/06/10/news/story3.html Accessed on September 7, 2006.

74 DSIRE Hawaii Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=HI04R&state=HI&...urrentPageID=1&RE=1&EE=0. Accessed 10-11-06.

Indiana

F

Number of customers 2004	**16**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW**
Eligible classes	**Residential, Schools**
Net excess generation	**Credited to customer's next bill indefinitely**
Limits on enrollment	**0.1% of a utility's most recent peak summer load**
Eligible technologies	**Solar Photovoltaics, Wind, Small Hydroelectric**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Despite opposition from several utilities, in 2004 the Indiana House passed HB1212 which would have required Indiana utilities to make renewable energy systems up to 2MW eligible for net metering. However, when the bill reached the Indiana Senate, Senator Jim Merrit (R-Indianapolis), Chair of the Senate Utility and Regulatory Affairs Committee, refused to give it a hearing. At the urging of supportive House members, the Indiana Utility Regulatory Commission (IURC) announced that it would initiate rulemaking in the summer of 2004.

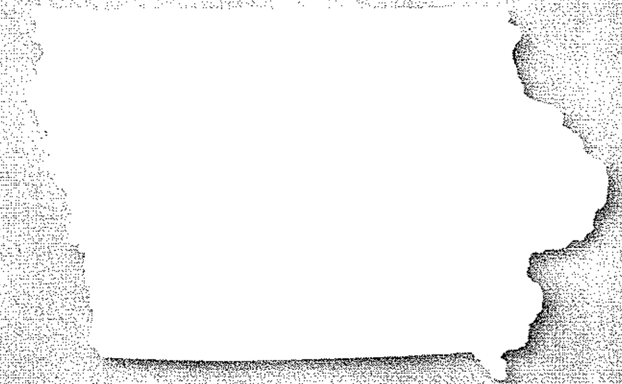
By September 2004, the IURC adopted net metering rules allowing residencies and k-12 schools to interconnect systems up to 10kW. Under IURC rules, net excess generation (NEG) is credited toward the customer's next billing cycle. The rules do not address when this banking expires and do not provide for the purchase of NEG.

Recommendations:

- Increase eligible system sizes to 2MW
- Expand eligible customer classes to include commercial, industrial and agricultural generators
- Allow the annual purchase of net excess generation at the retail rate
- Remove limits on statewide enrollment

000316

Iowa



C

Number of customers 2004	**8**
Change per million customers (2002- 2004)	**0%***
System size limit	**500kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased at avoided cost monthly**
Limits on enrollment	**None**
Eligible technologies	**Solar Photovoltaics, Wind, Biomass, Hydroelectric, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page18).

The Iowa Utilities Board adopted net metering guidelines in 1983.[75]

Customer-generators with alternative energy generation systems are permitted to net meter with investor-owned utilities, with no cap on system size or total enrollment. However, the Iowa Utilities Board granted waiver TF-01-293 to MidAmerican Energy in 2002, limiting individual net-metered systems to 500 kW. Interstate Power and Light has a similar waiver arrangement. Iowa's net-metering rules require NEG to be purchased at the utility's avoided-cost rate; however, MidAmerican Energy and Interstate Power and Light instead credit NEG for use in future months, as part of their waivers arrangement.[76]

Though the Iowa Utilities Board issued a draft order in December 1997 to eliminate net metering for residential renewable energy systems, public support of net metering resulted in the order being withdrawn.[77] Furthermore, despite utilities' efforts to overturn net metering and a ruling to this effect from the Iowa Supreme Court, FERC ultimately ruled in favor of net metering in Iowa.[78]

Recommendations:
- Credit NEG at retail rate annually
- Increase system size limit to 2MW for all customer classes
- Set interconnection standards as recommended by FERC and IREC

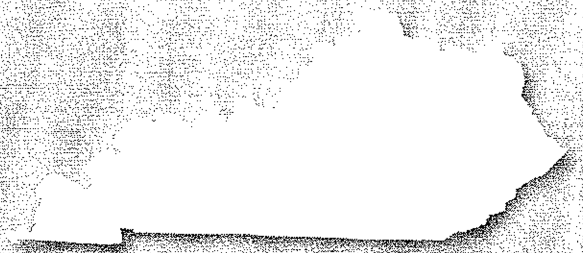
75 DSIRE. 2006. Database of State Incentives for Renewable Energy

76 Cook, Chris. 2004. State Supreme Court Rules in Favor of Small Generator, Orders Net Metering. IREC Connecting to the Grid. August 9. http://irecusa.org/articles/static/1/10[illegible]78572_987096450.html

77 http://www.nrel.gov/analysis/sren/sren20.html

78 Pearce, John. 2001. Renewable Energy Development Under Iowa's Alternate Energy Production (AEP) Statute. http://www.econ.iastate.edu/outreach/agriculture/programs/2[illegible]01_Renewable_Energy_Symposium/Pearce.pdf

Kentucky



D

Number of customers 2004	**2**
Change per million customers (2002- 2004)	**0%***
System size limit	**15kW**
Eligible classes	**Commercial, Residential, Nonprofit, Schools, Local Government, State Government, Agricultural, Institutional**
Net excess generation	**Credit at retail rate to customer's next bill indefinitely**
Limits on enrollment	**0.1% of a supplier's single-hour peak load during the previous year**
Eligible technologies	**Solar Photovoltaic**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities, rural cooperatives**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Kentucky's net metering regulations began in March 2002 when the Kentucky Public Service Commission began a 3 year pilot program requiring Louisville Gas and Electric and Kentucky Utilities Company to offer net metering to the first 25 customers. They then measured the costs and benefits to those 25 customers.[79]

Kentucky's current net metering rules were passed on April 22, 2004 by Governor Ernie Fletcher under SB 247. Interconnection standards were set in October 2004.[80]

Recommendations:

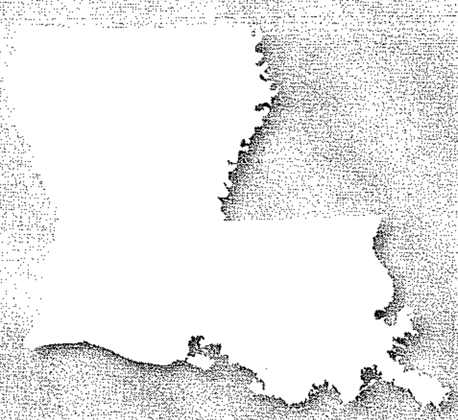
- Increase system size limit to at least 2 MW
- Do not limit overall enrollment capacity
- Offer all renewable technologies
- Allow all customer classes to participate

79 Issue: Net Metering, State Environmental Resource Center, http://www.sereonline.org/netmetering/stateactivity.html

80 Kalland, Stephen, 2004. KENTUCKY - Statewide Net Metering Legislation Enacted: IC Standards to Be Developed, IREC, May 8, http://www.irecusa.org/articles/static/1/108406768 987096450.html

000317

Louisiana



B

Number of customers 2004	**0**
Change per million customers (2002- 2004)	**0%***
System size limit	**100kW/ Commercial, Agricultural; 25kW/ Residential**
Eligible classes	**Commercial, Residential, Agricultural**
Net excess generation	**Credit at retail rate to customer's next bill indefinitely**
Limits on enrollment	**None**
Eligible technologies	**Solar Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells (Renewable Fuels), Microturbines**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

The Louisiana Renewable Energy Development Act (HB 789)[81] was introduced in March 2003 by Rep. William Daniel (D-District 68) after collaboration with Jeff Shaw, director of the Louisiana Solar Energy Society. It was signed into law on June 27, 2003 by Governor M.J. "Mike" Foster.

Though Rep. Daniel's original proposal was considered a strong net metering bill, it received opposition from Entergy Corp., a local investor-owned utility. After two months of negotiations, amendments were agreed upon which significantly weakened the bill, including removal of specific language designed to protect customer-generators during the interconnection process. The bill can now only cursorily be defined as a net metering provision, due to problems posed by ambiguous metering arrangements, fee structures, references to electricity "sales," and the bill's treatment of net excess generation.[82]

Developments since 2004: In 2005, the Louisiana Service Commission set regulations for net metering and interconnection similar to those of Arkansas. These standards required that net metering be offered by public owned utilities and rural electricity cooperatives. The renewable energy technologies included were solar, wind, hydroelectric, geothermal, and biomass for residential customers up to 25kW and commercial customers up to 100kW. The utilities are also required to pay for a two way meter, but customers are expected to pay an installation charge. Net excess generation is credited indefinitely at the avoided-cost rate.[83]

Recommendations:
- Include industrial customer classes as eligible and increase system size limit to 2MW
- Credit NEG at retail rate
- Remove external disconnect requirement

81 House Bill 789 http://www.lses.org/hb789.pdf
82 Kalland, Stephen and Rusty Haynes. 2003. The IREC Interconnection Newsletter, July 2003. NCSU Solar Center, Volume 6, Number 7. http://www.irecusa.org/articles/static/1/1057546474_987096476.html
83 DSIRE. 2006. Louisiana. www.dsireusa.org

Maine

D

Number of customers 2004	**0**
Change per million customers (2002- 2004)	**0%***
System size limit	**100kW**
Eligible classes	**Commercial, Residential, Agricultural**
Net excess generation	**Credit at retail rate to customer's next bill indefinitely**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Tidal Energy**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net-metering began in Maine in 1987 for cogeneration and small producing facilities with a maximum capacity of 100kW.[84] In December 1998, legislators passed an electrical restructuring bill that allowed the Maine Public Utilities Commission to amend net metering rules. The PUC's regulations did not go into effect until March 2000 and allowed excess electricity to go back on the grid for renewable energy under similar regulations as the 1987 standards.[85]

Recommendations:
- Increase system size for commercial, industrial and residential to 2MW
- Change treatment of net excess generation to carry credited retail rate over indefinitely
- Include interconnection standards that follow FERC or IREC standards
- Promote program to increase participation rates

1 DSIRE, 2006, www.dsireusa.org
2 Issue: Net Metering," State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html

C00018

Maryland

F

Number of customers 2004	**9**
Change per million customers (2002- 2004)	**0%***
System size limit	**80kW**
Eligible classes	**Commercial, Residential, Schools, Local, State, and Federal Government**
Net excess generation	**Granted monthly**
Limits on enrollment	**0.2% of state's adjusted peak load in 1998**
Eligible technologies	**Photovoltaics, Wind**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Beginning in 1997, Maryland first issued net metering legislation allowing up to 80 kW for residential customers and schools. The Maryland Energy Administration conducted a study of the economic impacts of net metering on utility companies after the program was first implemented and found them inconsequential.[86]

Developments since 2004: Since 1997, Maryland has expanded net metering regulations in May 2004, April 2005 and most recently in April 2006 under SB 167. In 2004, Governor Robert L. Ehrlich signed HB 1269 and expanded net metering to wind energy less than 80kW. Additionally, the law included private businesses and nonprofits under the residential eligibility class and schools under the institutional class.[87] Changes made in 2005 included biomass eligibility, an increase from 80kW to 200kW, and capacity limit to 500kW. SB 167 in 2006 made net metering eligible to solar, wind and biomass, allowed net excess generation to carry over annually and required additional dual meters in some cases. These provisions encouraged the Public Service Commission to develop a credit formula.[88]

Recommendations:
- Remove the limit on total capacity
- Amend eligible customer classes to include industrial
- Increase system size for commercial, industrial and residential to 2MW
- Amend treatment of net excess generation to be purchased at retail rate annually
- Remove requirements for additional dual meter

86 Cook, Christopher and Cross, Jonathan. 1999. A Case Study: The Economic Cost of Net Metering Maryland: Who Bears the Economic Burden? Maryland Energy Administration. http://www.e3energy.com/net-meter.pdf

87 State Renewable Energy Network, National Renewable Energy Lab. 2004. Maryland. State Renewable Energy News. Vol. 13. No. 2. http://www.nrel.gov/analysis/sren/sren38.html

88 DSIRE. 2006. Maryland. www.dsireusa.org

Massachusetts

F

Number of customers 2004	**170**
Change per million customers (2002- 2004)	**0%***
System size limit	**60kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited to next month's bill at average market rate**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Massachusetts currently has no state net metering legislation. The Department of Public Utilities allocated standards in 1982 through 220 Code of Massachusetts Regulation, Section 8.04(2)(C). Initially, renewable energy-based and combined-heat-and-power systems with a generating capacity limit of 30 kW were eligible for net metering; NEG was purchased at the avoided-cost rate.

In 1997, the Department of Telecommunications and Energy issued net metering amendments through 220 Code of Massachusetts Regulation, Section 11.04(7)(C). Changes included an increased system capacity from 30kW to 60kW, as well as allowing NEG to be credited to the customer generator's next bill at the average monthly market rate. Investor-owned utilities are required to offer net metering and municipal utilities may do so voluntarily.

The primary purpose of net metering regulations in Massachusetts was to increase the diversity of resources in the area and promote small power production facilities. It was not meant as part of a larger renewable energy initiative.[89]

Recommendations:
- Increase system size limit for eligible classes to 2MW
- Amend treatment of NEG to be purchased at retail rate annually
- Create interconnection standards similar to those recommended by FERC or IREC

89 Massachusetts Net Metering Program. No date. State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html

000319

Minnesota

A

Number of customers 2004	**233**
Change per million customers (2002- 2004)	**231%***
System size limit	**40kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Purchased at retail rate minus fixed costs**
Limits on enrollment	**None**
Eligible technologies	**Photovoltaics, Wind, Biomass, Hydroelectric, Municipal Solid Waste, CHP/Cogeneration**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

In 1983, Minnesota became the first state to adopt a net metering program by legislative statute. Minnesota's law applies to all investor-owned utilities, municipalities and rural electric cooperatives. Qualifying residential commercial and industrial facilities up to 40 kilowatts (kW) in capacity are eligible and there is no enrollment or total capacity cap.

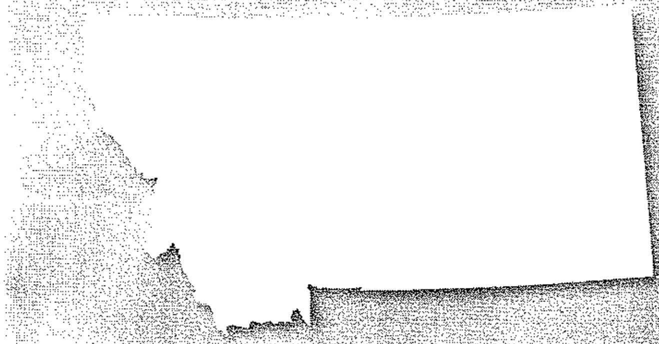
Regulated utilities must purchase net excess generation (NEG) at the utility's average retail rate, which equals the total annual revenue from sales of electricity minus the annual revenue resulting from fixed charges, divided by the annual class kilowatt-hour (kWh) sales. Wisconsin and Minnesota are the only states that require NEG be purchased at the modified retail rate.

Minnesota has adopted a state renewable portfolio standard (RPS) requiring utilities to use renewable energy to meet 10% of their retail electricity sales by 2015. Customer-generators retain ownership of all the renewable-energy credits (RECs) associated with renewable generation used to meet their on-site demand. Utilities purchase any RECs that adhere to NEG purchased from customer-generators.

Minnesota also offers progressive tax incentives for renewable energy generation, production incentives and sales tax exemption for wind energy, and a rebate program for grid-connected solar electric systems. On May 25, 2005, Governor Pawlenty signed into law the Omnibus Energy Bill of 2005 which established a tariff of up to 2.7 cents per kWh for community-based wind energy production.

Recommendations:
- Raise limits on eligible system sizes to 2MW
- Delete requirements for external shut-off switches and additional liability insurance

Montana



A

Number of customers 2004	**186**
Change per million customers (2002- 2004)	**5955%***
System size limit	**50kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited at retail rate to next bill; granted at end of annual billing cycle**
Limits on enrollment	**None**
Eligible technologies	**Photovoltaics, Wind, Hydroelectric**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

Montana's net-metering legislation was sponsored by Senator Jon Ellingson (D-Missoula) and supported by organizations such as the Renewable Northwest Project, National Resource Defense Council and the Montana Environmental Information Center.[90] When SB 409 passed unanimously in the Senate and in the House by 96-3, renewable energy advocates considered it one of the most progressive programs in the nation.[91] The bill applies to NorthWestern Energy, one of the largest providers in the region, and remains voluntary for rural cooperatives and non-investor owned utilities.[92]

Recommendations:
- Include all types of renewable energy in eligibility
- Increase system size limit for eligible classes to 2MW

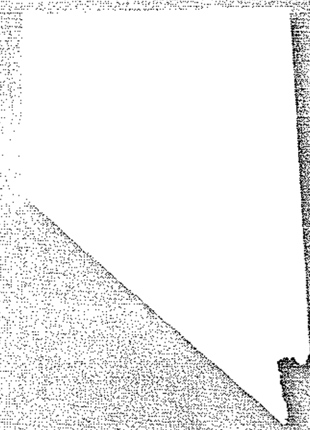
90 Becker-Dippmann, Angela. 1999. Montana Energy Laws: Net Metering Becomes Law in Montana. Pacific Northwest Energy Conservation and Renewable Energy Newsletter. April 30. http://www.newsdata.com/enernet/conweb/conweb40.html

91 Lawmakers Honored with Prestigious Eagle Award. The Energy Activist. Winter 1999. http://www.nwenergy.org/publications/activist/99_winter/99_winter_5.html

92 Programs through Utilities. 2005. Montana Department of Environmental Quality. http://www.deq.state.mt.us/Energy/Renewable/TaxIncentRenew.asp

000320

Nevada



A

Number of customers 2004	**100**
Change per million customers (2002- 2004)	**236%***
System size limit	**30kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited at retail rate to customer's next bill indefinitely**
Limits on enrollment	**1% peak capacity**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Wind, Biomass, Hydroelectric, Geothermal Electric**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

In 1997, Nevada enacted net metering legislation allowing solar and wind systems with a maximum capacity of 10 kW. Legislators revised regulations in 2001 under AB 661 and removed limits on electricity amounts a utility can receive. In 2003 AB 429 increased the system capacity from 10kW to 30kW and included hydropower as an eligible source.[93]

Developments since 2004: Nevada legislators amended net metering in 2005 by increasing system capacity to150kW for all classes under AB 236.[94]

Recommendations:
- Remove limits on total capacity
- Include all types of renewable energy technologies
- Increase system size limit to 2MW

93 "Nevada Incentives for Renewables and Efficiency" DSIRE:Database of State Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NV04R&state=NV&CurrentPageID=1&RE=1&EE=1

94 "Nevada Incentives for Renewables and Efficiency" DSIRE:Database of State Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=NV04R&state=NV&CurrentPageID=1&RE=1&EE=1

New Hampshire

A

Number of customers 2004	**81**
Change per million customers (2002- 2004)	**114%***
System size limit	**30kW**
Eligible classes	**Commercial, Residential, Industrial**
Net excess generation	**Credited at retail rate to customer's next bill**
Limits on enrollment	**0.05% peak capacity**
Eligible technologies	**Photovoltaics, Wind, Hydroelectric**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

New Hampshire passed net metering legislation under HB 485 in June of 1998. However, the law required that the state Public Utilities Commission make "reasonable interconnection requirements for safety and power quality". This commission included the state's largest utility company, Public Service of New Hampshire, the New Hampshire Office of Energy and Planning, and representatives from the inverter industry.[95] The legislation specified no date for the implementation and federal litigation from the PUC and PSNH stalled completion.[96] Rules for net metering and interconnection were not set until 2001.

Recommendations:

- Remove limits on total capacity
- Include all types of renewable energy technologies
- Increase system size limit to 2MW
- Carry over net excess generation indefinitely

95 Larson, Chris. 1998. From the States: IREC's Interconnection News. IREC. December, 1998. Vol. 1 No. 2 http://www.irecusa.org/articles/static/1/binaries/con9812.pdf

96 Renewable Energy 2000: Issues and Trends. Energy Information Administration, U.S. Department of Energy. Feb. 2001. p. 102 http://tonto.eia.doe.gov/FTPROOT/renewables/06282000.pdf

New Jersey

A

Number of customers 2004	**307**
Change per million customers (2002- 2004)	**30,141%***
System size limit	**100kW**
Eligible classes	**Commercial, Residential**
Net excess generation	**Credited at retail rate to customer's next bill; purchased at avoided-cost at end of annual billing cycle**
Limits on enrollment	**0.1% peak capacity or $2 million annual impact**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Anaerobic Digestion, Tidal Energy, Wave Energy, Fuel Cells (Renewable Fuels)**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

New Jersey established its net-metering program in 1999. This program capped net-metering system capacity at 0.1% of a utility's peak demand or at an annual financial impact to the utility of $2 million. It also limited eligible system sizes to 100kW and eligible customer classes to commercial and residential generators. However, the program provided for monthly banking of net excess generation (NEG) and required utilities to purchase NEG at avoided cost a the end of the annual billing cycle.

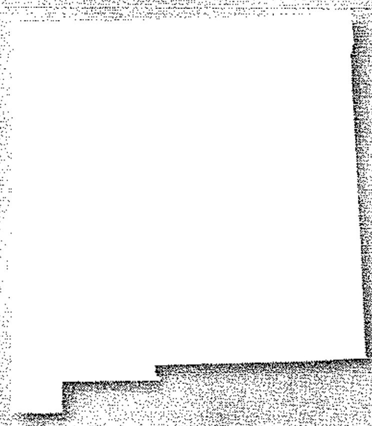
In March 2001, the New Jersey Board of Public Utilities (BPU) approved funding for renewable-energy programs, including a rebate program for renewable generation at homes, businesses, institutions and non-profit facilities. New Jersey also offers a full exemption from the state's 6% sales tax for all solar and wind-energy equipment. This exemption is available to all taxpayers.

New Jersey's status as the most effective state program is largely based on satisfactory components of the original program and the rapid growth in participating customers from 2002-2004.

In September 2004, with the strong support of then-Governor McGreevey, the New Jersey Board of Public Utilities (BPU) expanded the state's program to include solar technologies, wind, fuel cells, geothermal technologies, wave or tidal energy, methane gas from landfills and biomass. In addition, the new rules increased the maximum capacity of these systems from 100 kilowatts (kW) to 2 megawatts (MW) and removed the limitation on total enrollment.

New Jersey allows renewable energy credits (RECs) from customer-generators to apply toward the stringent requirements of the state's renewable portfolio standard (22.5% renewable by 2021) only if they are generated from systems that are eligible for net metering.

New Mexico



C

Number of customers 2004	**11**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW/ Commercial, Industrial, Residential**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to next bill or purchased at avoided-cost at end of annual billing cycle**
Limits on enrollment	**None**
Eligible technologies	**Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Fuel Cells, Municipal Solid Waste, CHP/Cogeneration, Microturbines**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities and cooperatives**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

In 1999, the New Mexico Public Regulation Commission (PRC) required all utilities to offer net metering to small power producers with systems up to 10 kilowatts (kW) in capacity. Municipal utilities, which are not regulated by the PRC, are exempt. There is no statewide cap on the number of systems eligible for net metering.

For net excess generation (NEG), the utility must either credit the customer for the net kilowatt-hours of energy supplied to the utility or pay the customer for the net energy supplied to the utility at the avoided cost. Monthly banking of NEG is allowed. If a customer with credits exits the system, the utility must pay the customer for any unused credits at the utility's avoided cost rate. Customer-generators retain ownership of all renewable-energy credits (RECs) associated with the generation of electricity.

Developments since 2004: In 2005, Governor Bill Richardson proposed expanding the state's net metering program to increase system size limits to 100kW, but cap total capacity at 1% of utilities' aggregate peak load. The New Mexico Senate amended the bill to include rural cooperatives, added several other requirements and attached a renewable portfolio standard. Governor Richardson pocket vetoed the final version of the legislation.

In a status report issued in October 2006, NMPRC staff recommended that the Commission change the state's net metering program to increase system size limits to 100kW, but give utilities the discretion to charge customer-generators for additional equipment and liability insurance.

Recommendations:

- Increase system size limit for commercial and industrial classes up to 2MW
- Remove the requirement for an additional external shut-off switch
- Reject PRC staff recommendations giving utilities discretion to charge additional interconnection fees and require additional liability insurance for systems larger than 50kW

000322

New York

C

Number of customers 2004	**87**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW (solar)/ Residential, Agricultural; 400kW (biogas) 125 kW (wind) / Agricultural; 25kW (wind)/ Residential**
Eligible classes	**Residential, Agricultural**
Net excess generation	**Credited to customer's next bill; purchased at avoided-cost at end of annual billing cycle**
Limits on enrollment	**0.1% peak capacity or $2 million annual impact**
Eligible technologies	**Photovoltaics, Wind, Biomass**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

The New York State legislature gave net metering its first push in the mid-nineties, creating legislation applicable only to residential photovoltaic systems with a maximum capacity of 10kW. The bill's language was similar to California's, with a few notable exceptions prohibiting extraneous insurance, fees, or controls.[97] However, Governor Pataki vetoed the bill citing "grave concerns relating to safety standards and the exposure of citizens and utility workers to serious or fatal injury," Utilities that opposed the bill raised these same safety issues.[98]

When the governor vetoed the bill, he made a commitment to institute incentives for solar energy. As a result, he proposed legislation that created a residential solar tax credit and net metering for solar systems.[99] The "Solar Choice Act of 1997" passed through the state legislature and was signed into law.[100] Developments in net metering legislation occurred in 2002, when SB 6592 made agricultural biogas systems eligible for net metering; in 2004, SB 4890-E (of 2003) further increased the scope of net metering legislation to permit residential wind turbines up to 25 kW and farm-based wind turbines up to 125 kW.

Recommendations:

- Increase system-size limits to at least 2 MW
- Purchase all NEG at retail rate
- Remove limits on aggregate enrollment
- Remove requirement for external disconnect switch

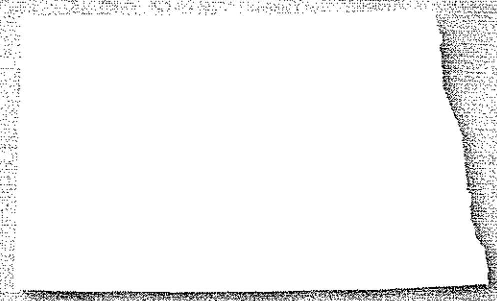
97 State Renewable Energy News. National Renewable Energy Laboratory. Summer 1996. Vol. 5. No. 2. http://www.nrel.gov/analysis/sren/sren14.html

98 State Renewable Energy News. National Renewable Energy Laboratory. Fall 1996. Vol. 5. No. 3. http://www.nrel.gov/analysis/sren/sren15.html

99 State Renewable Energy News. National Renewable Energy Laboratory. Summer 1997. Vol. 6. No. 2. http://www.nrel.gov/analysis/sren/sren17.html

100 State Renewable Energy News. National Renewable Energy Laboratory. Winter 1997. Vol. 6. No. 3. http://www.nrel.gov/analysis/sren/sren18.html

North Dakota



F

Number of customers 2004	**4**
Change per million customers (2002- 2004)	**0%***
System size limit	**100 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased by the utility at the avoided cost monthly**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Biomass, Geothermal, CHP, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor operated utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

In January 1991, the North Dakota Public Service Commission passed its net metering ruling, ND Administrative Code 69-09-07-09. The ruling established net energy billing and required that investor-owned utilities pay for power purchased from qualified facilities. However, the North Dakota Legislative Council's Committee on Administrative Rules objected to the PSC ruling, based on the fact that 1991 SB 2463, which would have required net metering for sales involving investor-owned utilities and rural cooperatives, failed to pass the Senate on a vote of 6 to 43. As a result, rural electric cooperative members are not subject to net metering legislation in North Dakota, and net metering is provided only by the three investor-owned utilities under the PSC.

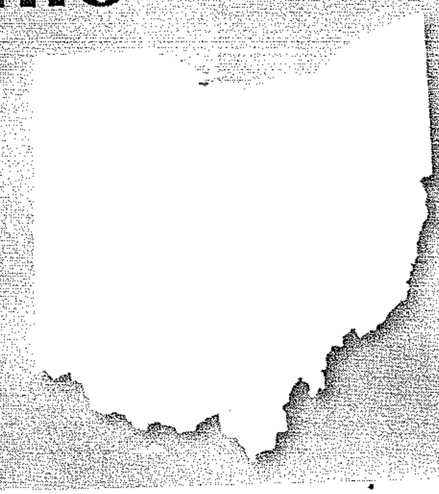
North Dakota's net-metering rules apply both to renewable-energy generators and combined-heat-and-power systems up to 100 kW in capacity. There is no statewide limit on the total capacity of all net-metered systems. At the end of a monthly billing period, the utility must purchase any NEG at the avoided-cost rate.

Recommendations:

- Increase system size limit to at least 2 MW
- Include rural electric cooperative members under net metering ruling
- Allow banking and carryover of NEG month-to-month

000323

Ohio



B

Number of customers 2004	**18**
Change per million customers (2002- 2004)	**0%***
System size limit	**No limit for renewable energy; 100 kW for micro turbines**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the next bill at the unbundled-generation rate**
Limits on enrollment	**1% of a utility's peak demand**
Eligible technologies	**Solar, Wind, Biogas, Hydroelectric, Fuel Cells, CHP/Cogeneration**
External shut-off	**No (if system is smaller than 10 kW)**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Ohio's net metering law took effect in 1999 as part of electric-utility restructuring legislation, requiring investor-owned utilities to provide net metering to customers using wind, solar, biomass, landfill gas, hydropower, fuel cells or micro turbines for electricity generation. Systems must explicitly be designed to offset part or all of the customer-generator's electricity demand, and there is no cap on system size, except for micro turbines, which are limited to 100kW. Each utility is required offer net metering until total generating capacity reaches 1% of the utility's aggregate customer peak demand in Ohio.

The Public Utilities Commission of Ohio (PUCO) initially ordered utilities to credit NEG at the retail rate. However, in June 2002, the **Ohio Supreme Court (Case No. 01-0573)** decided that such exchange was illegal, despite the comments submitted in support of PUCO's policy by the **American Solar Energy Society** (ASES), **American Wind Energy Association** (AWEA), **Solar Energy Industries Association** (SEIA), **Ohio Partners for Affordable Energy** (OPAE), **Ohio Environmental Council** (OEC) and the **Ohio Consumers' Council** (OCC).[101] Based upon the Supreme Court ruling, utilities must credit NEG to the customer at the utility's unbundled generation rate.

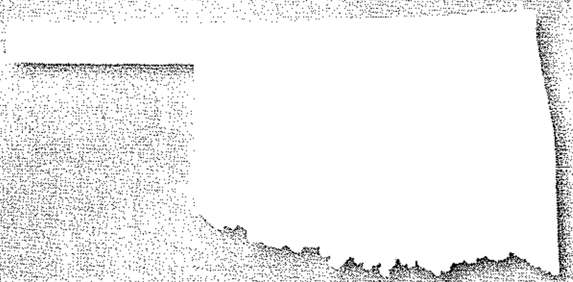
Developments since 2004: In December 2005, the PUCO opened a docket (Case No. 05-1500-EL-COI) to evaluate the state's current interconnection standards and net-metering rules.[102]

Recommendations:
- Credit NEG at avoided cost rate, at minimum
- Eliminate cap on total generating capacity

101 Green Energy Ohio. Ohio Supreme Court Limits Net Metering Incentive. http://www.greenenergyohio.org/page.cfm?pageId=322. Accessed 9-25-06.

102 Report by the Public Utilities Commission of Ohio. Case No. 05-1500-EL-COI. August 28, 2006.

Oklahoma



F

Number of customers 2004	**31**
Change per million customers (2002- 2004)	**0%***
System size limit	**100 kW (up to 25,000 kW a year)**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Granted to the utility monthly or credited to next bill at avoided cost**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Biomass, Geothermal, CHP, Municipal Solid Waste**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Oklahoma was first established by Oklahoma Corporate Commission (OCC) Order 326195 in 1988. The order requires investor-owned and municipal utilities under the OCC's jurisdiction to file net-metering tariffs applicable to customer-generators with renewable energy and combined-heat-and-power facilities. No statewide limit for aggregate net-metered capacity has been established, though individual system-size is limited to 100 kW. Under the order, rural co-operatives are not regulated by the OCC, and therefore cannot be required to offer net metering to their customers. Utilities are also not required to purchase net excess generation from customers, though a customer may request it. If the utility agrees, NEG is purchased at the avoided cost rate.[103]

Because of lack of public support, Oklahoma has been unsuccessful in addressing utility company opposition to net metering. Since 1999, several bills have been proposed by Rep. James Covey (D) with the intent of creating a statewide net metering rule, though none of these have become law due to opposition by utilities.

Developments since 2004: The Oklahoma Wind Power Assessment Committee, established by SB 1212 in 2004, has recommended that statewide net metering provisions encompassing all utilities be implemented in Oklahoma.

Recommendations:
- Include all utilities under net metering ruling
- Require purchase of all NEG from customer-generators at retail rate
- Increase system-size limit to at least 2 MW

103 DSIRE Ohio Incentives for Renewables and Efficiency. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=OK01R&state=OK&CurrentPageID=1&RE=1&EE=1. Accessed 10-9-06.

000324

Oregon

A

Number of customers 2004	**232**
Change per million customers (2002- 2004)	**1019%***
System size limit	**25 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited at retail rate to customers next bill or purchased by utility at avoided cost rate**
Limits on enrollment	**0.5% of a utility's peak load**
Eligible technologies	**Solar, Wind, Hydroelectric, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page18).

Oregon's original 1999 net metering law, HB 3219, was sponsored by the Committee on Commerce upon the request of the Renewable Northwest Project and the Solar Energy Industry Association of Oregon. It passed unanimously in both the House and Senate, and was supported by over twenty environmental groups, industry associations and utilities statewide. The law allowed net metering for customers with solar, wind, or hydropower systems up to 25 kW.

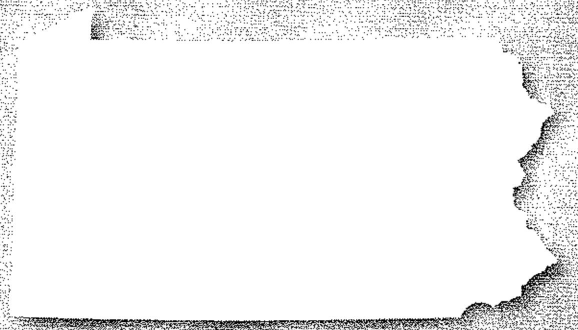
Presently, residential and commercial customers are permitted to net meter up to a total installed capacity of 0.5% of a utility's historic single-hour peak load. When installed capacity exceeds this limit, net metering may be limited by the regulatory authority.

Net excess generation is purchased at the avoided cost rate or credited to the customer-generator's next monthly bill. At the end of an annual period, any unused credit is granted to the electric utility.

Developments since 2004: In June 2005, SB 84 expanded net metering to include landfill gas, digester gas, waste, dedicated energy crops, and low-emission, nontoxic biomass derived from wood, forest, or field residues. Furthermore, the Oregon Public Utilities Commission is authorized to increase the 25-kW system limit for customers of investor-owned utilities.

Recommendations:
- Remove limits on enrollment
- Increase system size limit to at least 2 MW
- Purchase NEG at retail rate
- Credit excess NEG at end of annual period to customer-generator

Pennsylvania



F

Number of customers 2004	**89**
Change per million customers (2002- 2004)	**0%***
System size limit	**10kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Granted to the utility monthly**
Limits on enrollment	**None**
Eligible technologies	**Renewable energy and fuel cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Pennsylvania law introduced met-metering in 1996 under the Electricity Generation Customer Choice and Competition Act to include all renewable energy sources (including fuel cells up to 10kw).[104]

Developments since 2004: In November 2004, Governor Edward Rendell signed the Alternative Energy Portfolio Standards Act requiring net metering and interconnection standards to be set within 9 months. The rules were heavily influenced by the Mid-Atlantic Distributed Resources Initiative, or MADRI, consisting of a coalition of regional state utility commissions including Pennsylvania, the Federal Energy Regulatory Commission (FERC), PJM Interconnection L.L.C. (a large Mid-Atlantic and Northeast utility company), the U.S. Department of Energy, the EPA and the Institute of Electrical and Electronics Engineers Standard for Interconnecting Distributed Resources with Electric Power Systems or "IEEE 1547".[105] The PUC issued net metering and interconnection regulations in June and August of 2006, increasing system size limits to 50kW for residential and 1MW for non-residential. Additionally net excess generation is credited at the end of the month to the customer at the utilities' avoided cost.[106]

Recommendations:

- Increase system size limit to 2MW
- Purchase net excess generation annually
- Create interconnection standards similar to those recommended by FERC or IREC
- Credit customers at retail rate annually for net excess generation

104 "State Regulations" Resource Dynamics Corporation: Distributed Generation. http://www.distributed-generation.com/state_regulations.htm#Pennsylvania

105 "Notices: Pennsylvania Public Utility Commission" The Pennsylvania Bulletin. 23 March 2005. <http://www.pabulletin.com/secure/data/vol35/35-15/676.html

106 "Pennsylvania Incentives for Renewables and Efficiency" Database of State Incentives for Renewable Energy. 27 Sept. 2006. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=PA03R&state=PA&CurrentPageID=1&RE=1&EE=1

000325

Rhode Island

F

Number of customers 2004	**25**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the following month; granted to utility at the end of a 12-month period.**
Limits on enrollment	**1 MW**
Eligible technologies	**Solar, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Narragansett Electric Company**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

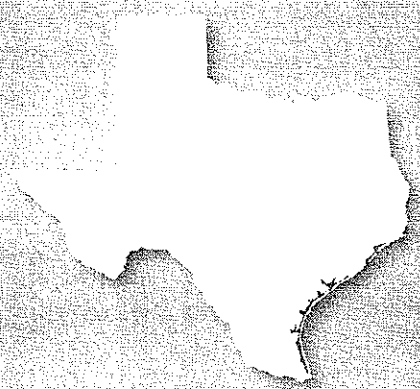
In 1998, after hearing a compelling case made by several state-based renewable energy experts, the Rhode Island Public Utilities Commission (PUC) required Narragansett Electric to provide net metering to customer-generators using renewable energy sources, including fuel cells, up to a 25 kW system limit. Eligible technologies are listed in Rhode Island's Utility Restructuring Act, R.I.G.L. §39-2-1.2(b).

At the end of each month, NEG is credited to the following month, and unused credits are granted to the utility at the end of a 12-month period. Narragansett Electric's aggregate net-metered capacity limit is one megawatt.

Recommendations:

- Remove system size limit and aggregate capacity limit
- Reimburse NEG at the retail rate
- Involve more utilities

Texas



F

Number of customers 2004	**16**
Change per million customers (2002- 2004)	**0%***
System size limit	**50 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased by the utility monthly at the avoided cost**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Hydroelectric, Fuel Cells, Hydroelectric, Tidal, Wave, Geothermal, Microturbines**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**Investor operated utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Texas, ordered by The Public Utility Commission of Texas under Substantive Rules, Section 23.66(f)(4), took effect in 1986. Part of the objective in promoting net metering was to promote small wind power and PV markets within the state. Beginning in 1999, however, statewide electricity market deregulation significantly hindered the efficacy of Texas' net metering rule. Though the right to interconnect to the grid was generally strengthened during the deregulation process, the ability to net-meter these interconnections diminished.[107]

Following deregulation, electric utilities comprised two categories with respect to net metering: (1) integrated IOUs outside the Electric Reliability Council of Texas (ERCOT) with a clear regulatory obligation to permit net metering up to 50 kW for facilities using renewable resources, and (2) electric cooperatives, municipal utilities and river authorities with no obligation to permit net metering. For deregulated entities within ERCOT, clear net metering rules do not exist, and no modifications to existing rules have been made in order to resolve this ambiguity.[108]

Developments since 2004: The Texas Million Solar Roofs Program, Texas Renewable Energy Industries Association, and Conservation Services Group are among the organizations which coordinated the **Texas RE-Connect Project**, which published its final report in April 2005. The objective of the report was to assist Texas utilities in sharing best practices and creating voluntary net metering and interconnection programs for small renewable energy systems.

Recommendations:
- Require all utilities to permit net metering through revision/clarification of existing rules
- Remove external shut-off requirement
- Increase system-size limit to at least 2 MW
- Credit all NEG to customer-generator at retail rate

107 Wiese, Steven M., John E. Hoffner, Erin Scott, Jane Pulaski, Russel Smith. 2005. Interconnection and Net Metering of Small Renewable Energy Generators in Texas: Final Report of the Texas RE-Connect Project. Million Solar Roofs Project. June 11. http://www.treia.org/pdf_files/Final Report.pdf

108 DSIRE. 2006. Texas Incentives for Renewable Energy. http://www.dsireusa.org/library/includes/incentive2.cfm?Incentive_Code=TX02R&state=TX&CurrentPageID=1&RE=1&EE=0. Accessed 10-9-06.

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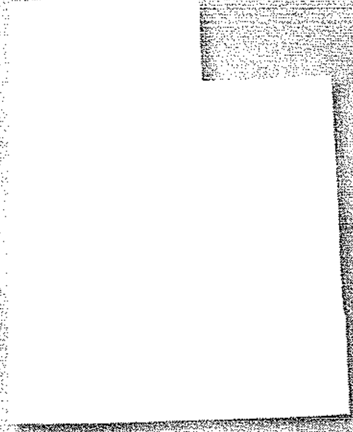
Utah



B

Number of customers 2004	**10**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the next bill at the retail rate; granted to the utility at the end of annual billing cycle**
Limits on enrollment	**0.1% of a utility's 2001 peak load**
Eligible technologies	**Solar, Wind, Hydroelectric, Fuel Cells**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities, Electric cooperatives**

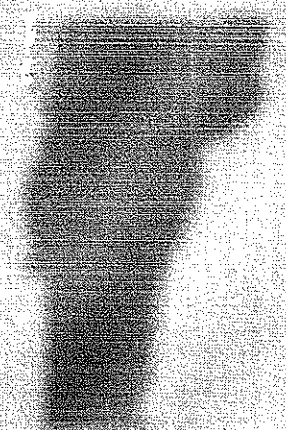
* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

On March 15, 2002, Governor Michael O. Leavitt signed into law HB 7, Net Metering of Electricity, sponsored by Rep. Gordon E. Snow (R). The bill was recommended by the Public Utilities and Technology Interim Committee, and passed unanimously in both the House and Senate. The legislation received support from a broad coalition of interested parties, including environmental groups and Utah Power.

Utah's net-metering law requires all electric utilities and cooperatives, excluding municipal utilities, to permit interconnection of renewable energy systems to the electric grid. Eligible renewable energy systems include fuel cells, solar, wind or small hydropower facilities with a maximum generating capacity of 25 kilowatts. Total participation of customer-generators is restricted to 0.1% of the 2001 cumulative generating capacity of the electrical corporation's peak demand. The utility is required to credit the customer for any NEG at the utility's avoided cost rate or higher. NEG is carried over monthly to the next customer's next bill until the end of each calendar year, at which point any remaining NEG is granted to the utility. Utilities are not permitted to issue additional charges or fees for net-metered customers, unless authorized to do so by the Utah Public Service Commission.

Recommendations:
- Increase system size limit to at least 2 MW
- Eliminate the cap on total eligible capacity
- Require municipal utilities to permit interconnection
- Require purchase of NEG at retail rate

Vermont



B

Number of customers 2004	**67**
Change per million customers (2002- 2004)	**152%***
System size limit	**15 kW for Residential and Commercial; 150 kW for Agricultural**
Eligible classes	**Residential, Commercial, Agricultural**
Net excess generation	**Credited to the next bill at the retail rate; granted to the utility at the end of annual billing cycle**
Limits on enrollment	**1% of peak demand for 1996 or current year**
Eligible technologies	**Solar Photovoltaic, Wind, Biomass, Fuel Cells**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

Vermont's net metering program is generally limited to renewable energy systems under 15 kW. However, farmers who generate electricity using eligible renewable-energy resources may net meter systems up to 150 kW, based on certain conditions. There is also a provision for "group net metering," allowing farm systems to credit on-site generation against all meters designated to the farm system. The state public service commission may allow net metering for up to 10 systems per year for non-farm generators greater than 15 kW, but no greater than 150 kW of capacity. A utility and on-farm system owner may also jointly petition the PSB for permission to exceed the 1% aggregate enrollment cap. NEG is granted to the utility without compensation to the customer-generator annually.

Vermont's initial net metering legislation, H.605, was sponsored by Rep Kathleen C. Keenan (D), and became law on April 22, 1998. Despite reservations expressed by utility companies, H.605 was amended in 1999 by H.705, and in 2002 by S.138, increasing the maximum capacity of farm systems and expanding eligible energy sources for net metered systems.

Developments since 2004: 212 net-metered systems (54 wind, 157 solar and one farm-waste methane), with an aggregate capacity of 811 kW, had received a "Certificate of Public Good" in Vermont as of November 2005.

Recommendations:
- Remove capacity cap on total enrollment
- Increase system size limit to at least 2 MW
- Require utilities to purchase NEG at the retail price annually

000327

Virginia

D

Number of customers 2004	**19**
Change per million customers (2002- 2004)	**0%***
System size limit	**10 kW for Residential; 500 kW for Non-Residential**
Eligible classes	**Residential, Commercial, Nonprofit, Schools, Government**
Net excess generation	**Purchased at retail rate for renewable energy; purchased at avoided cost for non-renewable energy**
Limits on enrollment	**0.1% of annual peak demand**
Eligible technologies	**Solar, Wind, Hydroelectric**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Virginia was originally established in 1999 as part of SB 1269, an amendment to the Virginia Electric Utility Restructuring Act. The net metering rules were developed in part through a July 1999 Commission survey sent to utilities and renewable energy stakeholders. Under SB 1269, Virginia's net-metering law applied to residential systems up to 10 kW in capacity and non-residential systems up to 25 kW in capacity. Eligible systems were limited to solar, wind or hydro energy sources, and customer-generators were not credited for NEG unless a power purchase agreement was established with the utility. Aggregate enrollment capacity was established at 0.1% of each electric utility's peak demand forecast for the previous year.

Developments since 2004: In 2004, maximum capacity for non-residential distributed generation systems was increased from 25 kW to 500 kW by SB 651. On March 31, 2006, Virginia Governor Tim Kaine signed HB 1541, extending eligibility to all renewable energy generation systems based upon "energy derived from sunlight, wind, falling water, sustainable biomass, energy from waste, wave motion, tides, and geothermal power." (Previously, net metering was limited to solar, wind or hydro resources.) HB 1541 also permitted net-metering systems to be eligible for lease financing.

Recommendations:
- Eliminate cap on total enrollment capacity
- Purchase all NEG at the retail rate
- Eliminate requirements for external disconnect switch and additional insurance
- Increase system-size limit to at least 2 MW

Washington

D

Number of customers 2004	**73**
Change per million customers (2002- 2004)	**0%***
System size limit	**25kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to the next bill at the retail rate; granted to the utility at the end of annual billing cycle**
Limits on enrollment	**0.25% of a utility's 1996 peak load**
Eligible technologies	**Solar, Wind, Biogas, Hydroelectric, Fuel Cells, CHP/Cogeneration**
External shut-off	**No**
Additional insurance	**No**
Utilities involved	**All utilities**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

Net metering in Washington State was first enacted in 1998 by the Revised Code of Washington chapter 80.60, establishing the limit on total capacity at 0.25% of a utility's peak demand during 1996, and reserving at least .05% for production from solar, wind, or hydropower. Under the original code, NEG was credited at the retail rate to the customer's next bill, with remaining NEG granted to the utility without compensation to the customer at the beginning of the calendar year.

Developments since 2004: Substitute HB 2352 of 2006 increased system size limits from 25 to 100 kW, and expanded the definition of renewable energy to include solar, wind, hydro, biogas from animal waste, or combined heat and power technologies (including fuel cells). HB 2352 also increased the total capacity cap to 0.5% of a utility's peak demand in 1996, effective 2014. Unused NEG is still credited to the utilities on April 30 of each calendar year.

The revised bill was sponsored by Representatives Morris, Hudgins, and B. Sullivan, with supporting testimony provided by a representative of the Department of Community, Trade & Economic Development. Despite opposing testimony by a representative of Avista Corporation, HB 2352 passed with an overwhelming majority in both the House and Senate and took effect on June 7, 2006.

Recommendations:
- Eliminate the cap on total eligible capacity
- Increase the system size limit to at least 2 MW
- Require utilities to purchase NEG at the retail rate annually

Wisconsin

A

Number of customers 2004	**212**
Change per million customers (2002- 2004)	**127%***
System size limit	**20 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Purchased at retail rate for renewable energy; purchased at avoided cost for non-renewable energy**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Biomass, Hydroelectric, Geothermal Electric, Municipal Solid Waste, CHP/Cogeneration**
External shut-off	**Yes**
Additional insurance	**Yes**
Utilities involved	**Investor-owned utilities**

* Growth is calculated as change in the number of net metering customers per million utility customers to account for variable population densities (See page 18).

Wisconsin's net metering legislation is based upon a letter order issued by the Public Service Commission of Wisconsin (PSCW), confirmed on September 18, 1992, and applicable to all investor-owned utilities. Though rural electric cooperatives in Wisconsin are not rate-regulated by PSCW, they often voluntarily abide by the Commission's rulings; several rural electric cooperatives are preparing to offer net metering to their customers.[109]

In Wisconsin, net metering is available to customer-generators with a maximum system capacity of 20 kW. All systems are eligible, including renewable energy and combined heat and power. Utilities pay the retail rate for NEG produced by renewable energy-run systems, while customer-generators using non-renewable resources receive the avoided-cost rate.

Developments since 2004: In January 2006, the PSC accepted a proposal by investor-owned We Energies to permit customers with wind turbines ranging from 20-100 kW in capacity to be eligible for net metering. The first 25 eligible applicants will be permitted to participate in this program for a 10-year term.

Recommendations:
- Increase system size limits to at least 2 MW
- Include rural electric cooperatives under net metering legislation
- Do not require an external disconnect switch or additional insurance

109 State Environmental Resource Center, http://www.serconline.org/netmetering/stateactivity.html. Accessed 9-25-06.

Wyoming

B

Number of customers 2004	**11**
Change per million customers (2002- 2004)	**0%***
System size limit	**25 kW**
Eligible classes	**Commercial, Industrial, Residential**
Net excess generation	**Credited to next bill; purchased at avoided cost at the end of the annual billing cycle**
Limits on enrollment	**None**
Eligible technologies	**Solar, Wind, Biomass, Hydroelectric**
External shut-off	**Yes**
Additional insurance	**No**
Utilities involved	**Investor-owned utilities, Electric cooperatives**

* Growth is calculated as zero because the state did not exceed 67 participating customers per million customers (see Appendix A).

On February 22, 2001, Governor Jim Geringer signed into law HB195[110], requiring Wyoming's investor-owned utilities, including electric cooperatives and irrigation districts, to offer net metering for solar, wind, and hydroelectric systems of 25 kW or less. The legislation took effect on July 1, 2001.[111] Upon the passage of Senate Bill 106 on July 1, 2003, biomass also became an eligible renewable fuel. Net excess generation in one month is credited to the following month. At the end of an annual billing period, the utility must purchase unused credits at the avoided-cost rate.

Developments since 2004: In 2006, The Wyoming Public Service Commission (PSC) proposed to adopt and incorporate two sections of EPAct 2005 verbatim into its Procedural Rules and Special Regulations, requiring utilities to allow interconnection based on the IEEE 1547 standard, and requiring utilities to offer net metering to customers. A public hearing took place on November 1, 2006 to address this issue.[112]

Recommendations:
- Increase system-size limit to at least 2 MW
- Remove requirement for external disconnect switch
- Purchase NEG at the retail rate

110 Wyoming State Legislature. 2001. http://legisweb.state.wy.us/2001/introduced/hb0195.htm
111 State Environmental Resource Center. http://www.serconline.org/netmetering/stateactivity.html. Accessed 8-29-06.
112 Haynes, Rusty. 2006. Interstate Renewable Energy Council "Connecting to the Grid" Newsletter, Vol. 9 No. 10. http://www.irecusa.org/connect/enewsletter.html. Accessed 9-18-06.

000329

IV: Worst Practices

Indiana & Arkansas

The crafting of the net metering programs in Indiana and Arkansas provides a useful illustration of how the good intentions of state legislators can go astray during the evolution of policy through the regulatory process.

While our analysis did not rank either Arkansas or Indiana as having the worst net metering program, we did find that both the Indiana Utility Regulatory Commission (IURC) and the Arkansas Public Service Commission (APSC) failed to establish effective net metering programs largely because of undue deference given to utilities during the rulemaking process.

In the absence of explicit federal legislation to guide the development of individual state net metering programs, both the Indiana and the Arkansas state legislature delegated the task of developing comprehensive net metering rules to their respective state commissions. Both commissions released draft proposals of their net metering rules for public comment. In addition, each held at least one public hearing during which staff heard comments on net metering from utilities, individual customers, public interest groups and other stakeholders.

Despite the diversity of the comments by stakeholders in both states, key provisions of the resulting regulations (effective as of 2006) reflect the concerns of regulated utilities, most of whom proposed modifications to the draft rules that effectively restricted the number of eligible customers and often unfairly limited the economic benefits of net metering.

APSC's decision to give utilities net excess generation at the end of each month instead of facilitating month-to-month banking can be traced to utility concerns about cross subsidy issues and fears of lost revenue. Similar concerns by utilities in Indiana led its commission to adopt very restrictive limits on eligible system sizes and exclude many customer classes altogether.

Utility concerns over lost revenue were more effectively allayed than anyone may have imagined. In the first two years of its program, Arkansas recorded exactly zero participating customers. By 2004, Arkansas and Indiana could not count more than 20 participating customers between them.

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Indiana

Preventing Legislators from Balancing Economic Interests

Despite overwhelming support for a net metering bill passed unanimously by the Indiana House of Representatives in February 2004, State Senator James Merritt, Chair of the Indiana Senate Utility and Regulatory Affairs Committee, refused to consider the issue,[113] claiming that it "invaded the province of IURC" and that the Commission alone should be responsible for developing net metering rules.[114]

In September 2004, the IURC adopted a formal net metering rule for Indiana, "albeit on a more modest basis," than proposed under HB 1212 or requested by the specific state legislators.[115] Unlike the bill passed in the State House, which would have required the state's electric utilities to make net metering available to any customer with a renewable energy system up to 2 MW in size, the net metering provisions issued by IURC only require the state's investor-owned utilities to make net metering available for residential customers or K-12 schools with systems up to 10 kW. In addition, IURC required eligible customer-generators to obtain insurance for net metered systems of at least $100,000 and gave utilities the discretion to require an additional external shut-off switch installed at the customer's expense.

In 2002, long before issuing its net-metering rules, IURC began collecting information about distributed generation that was to be used in the development of the state's comprehensive net metering rules.[116] IURC issued a request for responses to a list of technical questions associated with initiating a statewide net metering program. By March of 2002, eight of the state's utilities as well as the Citizen Action Coalition (CAC) submitted their comments in response to the IURC's request.[117] Although the Commission initially intended for the program to provide incentives for individual customers to invest in small-scale renewable generation,[118] the language of its final rules reflects substantially the comments made by the state's utilities.

One main argument made by Indiana's utilities involved unfounded claims that net metering results in "the subsidization of customers with net metering by other customers and by the utility,"[119, 120] an argument known as 'cross-subsidization' (see pages 70-71). In order to limit this problem, the utilities suggested that, "net metering should be limited to a small generator (i.e. maximum 10 kW nameplate rating) for primarily residential or small commercial application."[121]

113 Indiana regulators adopt final net metering rules, but AG still must review. (2004) Electric Utility Week. The McGraw-Hill Companies, Inc. Sept 13. P. 21

114 DeAgostino, Martin. (2004) Heat deposit bill off Senate's plate; Power generating, utility issues seen URC responsibility. South Bend Tribune Corp. Feb. 18. P. A2

115 Indiana regulators adopt final net metering rules, but AG still must review. (2004) Electric Utility Week. The McGraw-Hill Companies, Inc. Sept 13. P. 21.

116 Indiana Utility Regulatory Commission (IURC). (2002, 2003)Distributed Resources Workgroup. IURC. http://www.in.gov/iurc/utilities/energy/drw/drw_index.html

117 Indiana Utility Regulatory Commission Staff. (2002) Distributed Generation White Paper. IURC. Jan. 25. http://www.in.gov/iurc/utilities/energy/drw/whitepaper_012502.pdf

118 Ibid.

119 American Electric Power. 2002. Comments of Indiana Michigan Power Company, d/b/a American Electric Power, on the Indiana Utility Regulatory Commission Staff's Distributed Generation White Paper. IURC. March 1. http://www.in.gov/iurc/utilities/energy/drw/aep_comments_030102.pdf

120 Southern Indiana Gas and Electric Company, d/b/a Vectren Energy Delivery of Indiana, Inc. 2002. Response to Distributed Generation Rule Making. IURC. February 28, 2002. http://www.in.gov/iurc/utilities/energy/drw/sigeco_comments_030102.pdf

121 Brothers, Ronald J. 2002. Comments of PSI Energy, Inc. and Cinergy Corp. Concerning the Indiana Utility Regulatory Commission's Advanced Notice of Proposed Rulemaking Concerning Distributed Generation. Indiana Utility Regulatory Commission, Mar. 1. http://www.in.gov/iurc/utilities/energy/drw/psi_comments_030102.pdf

000330

The final rules reveal that the utilities were effective at persuading the IURC to limit eligible system sizes to 10kW, despite entreaties by the state legislature to allow net metering of systems up to 2 MW.

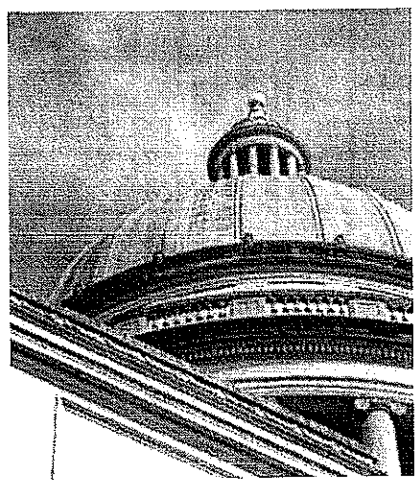
Indiana's experience with net metering reflects how state regulations crafted to protect the economic interests of one sector (electrical utilities) may have unintended negative consequences on other sectors (like precision tool manufacturing).

One Indiana utility, Richmond Power and Light, argued for restricting eligible customer classes because "in the context of industrial or commercial customers," who may be capable of generating a substantial amount of their electricity demand on-site, allowing month-to-month banking would be "disastrous and confiscatory."[122] Indiana Technology and Manufacturing Companies, ITAMCO, with 75 employees in its 100,000-square-foot factory, "where precision work requires costly air conditioning," countered that on-site power generation would reduce operational costs and make the company more economically competitive. [123] David Neidig, marketing VP at ITAMCO, explained that the company's interest in participating in net metering was partly because it "is a great way for (ITAMCO) to be more competitive as an Indiana manufacturer, and at the same time be environmentally conscious, and be a good neighbor of the community." [124] ITMACO noted that, because a 1.5 MW wind turbine would cost the company about $1.5 million, net metering was "essential to (ITAMCO's) cost equations" when planning to invest in the its renewable energy system. In the end, IURC's net metering rules excluded commercial and industrial customers and Indiana companies like ITAMCO were unable to benefit from net metering.

Indiana's experience with net metering reflects how state regulations crafted to protect the economic interests of one sector (electrical utilities) may have unintended negative consequences on other sectors (like precision tool manufacturing). More importantly, Indiana's experience reveals how, in the absence of explicit statutory guidance, state public utility commissions can thwart the intention of legislators seeking to more effectively balance the economic interests of the state.

Arkansas

Allowing Utilities to Discourage Participation



In response to increasing demand for energy in Arkansas, on April 13, 2001, the state legislature enacted the Arkansas Renewable Energy Development Act of 2001, which mandated that electric utilities make net metering available to residential, commercial and agricultural customers. [125] The legislature intended the program to increase the use of renewable energy sources, decrease the use of foreign fossil fuels and encourage customers to invest in renewable energy technology.[126] Eligible technologies under the Act included solar, wind, hydroelectric, geothermal, and biomass systems with generating capacities up to 25kW for residential

122 Indianapolis Power & Light Company. 2002. Comments and Attachments to Advanced Notice of Proposed Rulemaking on Distributed Resources. IURC. Feb.15, 2002. P. 3. http://www.in.gov/iurc/utilities/energy/d.../drw_index.html accessed on August 10. 2006.

123 DeAgonstino, Martin. (2004) Company looks to wind for savings; Bill benefits small-scale power generators. South Bend Tribune (Indiana), Monday Marshall Edition. Feb. 16. P. C1.

124 ibid.

125 Avery, Chad. (2002) Survey of Legislation. 2001 Arkansas General Assembly. Regulated Industries. 24 U. Ark. Little Rock L. Rev. 595, 600.

126 The Arkansas Renewable Energy Development Act of 2001. Ark. Code Ann. § 23-18-602(a).

customers and 100kW for commercial and agricultural customers. However, although the statute makes net metering available for several technologies and multiple customer classes, it does not establish the rates, terms or conditions for net metering contracts. Instead, the legislature allocated this task to the Arkansas Public Service Commission (APSC). As in Indiana, utility influence over the final design of the Arkansas' net metering regulations effectively undermined the legislature's intentions by creating economic disincentives for investments in renewable energy systems.

As in Indiana, utility influence over the final design of Arkansas's net metering regulations effectively undermined the legislature's intentions by creating economic disincentives for investments in renewable energy systems.

Instead of allowing a net metered customer to bank net excess generation each month, Arkansas's net metering rules grant all excess generation to the utility at the end of an applicable billing period. The limitation on banking in the final rule reflects the suggestions of the regulated utilities and indicates that APSC staff was more deferential to utility comments than to the public's interest in expanding the use of renewable technologies.

Initially, APSC prepared two versions of draft net metering rules, the first draft on December 7, 2001 and a revised draft on February 20, 2002. APSC received comments submitted in response to each draft and held a public hearing to gather additional information on net metering. Despite the strong support for allowing month-to-month banking by Arkansas's Attorney General and individual utility customers, the Commission adopted the position of the utilities, holding that net excess generation should be donated to the utility at the end of every monthly billing cycle.[127]

The APSC supported its decision by parroting the arguments submitted by regulated utilities. First, the utilities argued that allowing month-to-month banking would enable the customer-generator to "become a quasi-power supplier to the electric utility as opposed to offsetting customer's requirements for electricity."[128] This argument rests on a definition without a distinction. Customer-generators that are offsetting generation from the utility are necessarily supplying that generation to themselves. Monthly banking does not directly compensate a net metered customer for electricity generation. It merely credits the same customer to offset future demand so that self-generating customers are not artificially beholden to the monthly billing cycles of regulated utilities. If offsetting demand makes sense as a matter of public policy, then so does monthly banking, especially as banking allows excess generation from one customer to be used to meet another customer's demand.

Second, Arkansas utilities claimed that banking would over-compensate the customer-generator, since NEG would be credited at the retail price of electricity, which includes costs associated with transmission, distribution and administration.[129] Electricity generated and consumed by the customer always offsets electricity supplied by the utility at the retail rate, regardless of whether the electricity is consumed this month or next. Monthly banking allows excess generation produced this month

127 Arkansas Public Service Commission. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules. Docket No. 02-046-R, Order No. 3. APSC. June 3. P. 5-7.

128 Elford, W.W. II. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules. Docket No. 02-046-R, Initial Comments of American Electric Power, Inc. Southwestern Electric Power Company. APSC. April 2, 2002. p 3.

129 Arkansas Public Service Commission. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R, Order No. 3. APSC. June 3. P. 5-7.

to offset the same kind of electricity consumed the next. If the electricity is no different, why should the price of the offset change? As well, the excess generation not credited to the customer in one month is consumed by the grid and sold to other customers at the retail rate. By profiting from the excess electricity produced by customer-generators, are not utilities being 'overcompensated' for electricity they did not produce?

Finally, utilities argued that banking would provide more benefits to the customers already participating in net metering rather than encouraging more customers to participate. By this logic, the entire net metering program should be rejected as merely providing economic compensation for customers with existing renewable energy systems. Since the ability to bank net excess generation decreases the payback time for renewable energy installations, it provides as much of an economic incentive to invest in new renewable systems as the inherent ability of any net metering program does by offsetting customer utility bills in any given month.

States that allow monthly banking of net excess generation (NEG) experience larger and faster growth in participation than states that disallow it. Four out of five of the states that experienced the greatest growth in net metering participation from 2002-2004 allow month-to -month banking of NEG.

More importantly, the argument that monthly banking does not encourage greater rates of participation is contradicted by empirical data. Our analysis of participation rates in state net metering programs from 2002-2004 finds that states that allow monthly banking of NEG experience larger and faster growth in participation than states that disallow it. Four out of five of the states that experienced the greatest growth in net metering participation from 2002-2004 allow month-to-month banking of NEG.[130]

In Arkansas, APSC's decision to prevent monthly banking of NEG increased the pay-back period for individual net metered systems significantly.[131] Consequently, the longer pay-back periods effectively discouraged customer investment in renewable technology and impeded the expansion of renewable energy sources.[132] Although the state's Attorney General and three individual electric customers raised many of the points we raise here, APSC maintained that no evidence suggested that allowing customers to bank excess generation would encourage more customers to invest in renewable technology.

APSC further limited customer participation in net metering by agreeing with utility suggestions that the rules should limit the size of eligible net metered system so as not to "exacerbate" cross-subsidization issues.[133]

130 New Jersey, Montana, Oregon and California all allow monthly banking of NEG credited at the retail rate. Hawaii, with the fifth largest increase in participation from 2002-2004, grants NEG to the utility at the end of each month.

131 Ball, William. (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R. Reply Comments of William Ball. ASPC, April 2. http://www.apscservices.info/PDF/02/02-046-r_20_1.pdf

132 ibid

133 Arkansas Public Service Commission (2002) In the Matter of a Generic Proceeding to Establish Net Metering Rules, Docket No. 02-046-R, Order No. 3. APSC. June 3. P. 5-7. http://www.dsireusa.org/documents/Incentives/AR03Ra.pdf

Cross-Subsidization:

The Boogey-Man of Net Metering

Utilities argue that net metered customers continue to benefit from transmission lines and other utility amenities even though they are supplying their own electricity. The cost of these other things is, therefore, borne by non-participating customers who end up paying higher electricity rates. In a 1999 report on net metering for the Solar Energy Society of Canada, Andrew Pape explains the cross-subsidization argument this way:

"There are three types of subsidies implicit in net metering. First, bundled retail rates typically include fixed costs. By crediting customer-generators based on retail rates, they may effectively avoid some of these fixed costs (e.g. fixed T&D costs), although they continue to benefit from them (e.g. standby service). Second, power production from customer-generators that is credited by the utility may coincide with periods of the day or year when power is less valuable (e.g. summer days), yet customer-generators may consume utility power at zero net cost during periods when power is more valuable. Finally, net metering programs may entail additional costs that are recovered from all ratepayers, not just program participants."[134]

While couched in a level of economic sophistication, the cross-subsidization argument is a contortion of logic bordering on the absurd. It is akin to arguing that customers who use less electricity, and thus pay less, should have to pay a monthly fee to make up the difference. Otherwise, the utility will increase costs for the customers who use more electricity.

Whatever merit exists to the cross-subsidization argument stems entirely from the fact that utilities enjoy a monopoly on the transmission and distribution systems that all customer-generators are required to use. Utilities do not enjoy a monopoly on transmission by divine right. Since utility monopoly is the result of policy made ostensibly to promote the public good, policymakers may surely change the policy in pursuit of even greater public good.

For the cross-subsidization argument to make much sense, utilities must mischaracterize net metering as a separate electricity sale from the net metered customer to the utility, rather than as an offset of electricity demand. The cross-subsidization argument is irrelevant until a net metered system generates more electricity than is being consumed by the customer and the meter runs backward. It is only when the meter runs backward that the utility is crediting the customer for net excess generation contributed to the grid. Until then, there is no more cross-subsidy inherent in the arrangement than there would be when a utility customer, for example, installs an energy efficient air conditioner. Not demanding as much electricity from the grid is not the same thing as requiring the utility to credit excess electricity at the retail rate. It is simply demanding less.

Even when net metered customers are generating excess electricity, there is little justification for limiting net metering in some crude attempt to spread the fixed costs of transmission and distribution equitably among ratepayers. To begin with, many utilities already 'unbundle' fixed costs by charging an initial connection fee and/or delineating separate transmission and distribution charges on a customer's bill. Under these circumstances, the fixed transmission, distribution and administration costs associated with managing the grid are not subsumed by the retail rate of electricity and thus the cross-subsidization argument is not a justification for denying net metered customers the full credit for the electricity they generate.

Cross-subsidization already occurs as a result of fixing transmission costs in the first place. Presumably, customers benefit from the transmission grid in ways not reflected by their electricity

134 Pape, Andrew (1999): Clean Power at Home. David Suzuki Foundation: Ottawa (p. VIII). http://www.davidsuzuki.org/files/clean.pdf

000332

bill. It costs much more to transmit electricity to some areas than others. Customers who consume electricity close to where it is generated subsidize the transmission of electricity to customers who reside far from power plants. Retail prices do not reflect the unequal costs of transmission lines and load losses. Instead, all customers are charged as if they contributed equally to transmission expenses. Even today, transmission system controllers must use brownouts and rolling blackouts rather than electricity price to manage demand in excess of capacity[135]. These crude tools require some ratepayers to subsidize electrical reliability for others. And yet utilities remain largely silent about these inherent inequities until the issue of net metering is raised.

The second component of the cross-subsidization argument (that crediting excess generation rewards off-peak generation at on-peak prices) is even more preposterous. Multiple empirical studies demonstrate that renewable energy DG systems (particularly solar PV systems) generate excess electricity during peak demand periods.[136] Rather than net metered customers claiming credit for excess electricity when it is "cheap" and applying the credit when electricity is "expensive", in practice the opposite has been the case. By providing excess electricity to the grid during periods of peak demand, the net metered customer not only is helping the resource-constrained utility meet its demand, but is offsetting the most expensive type of electricity, that provided by pricey "peaking facilities" that come online only when base loads are exceeded. What's more, if the utility fails to credit excess generation at the retail price of electricity, the utility will simply be taking the excess generation from net metered systems and charging other customers the full price. Talk about cross-subsidization! Without paying for any additional infrastructure investment, the utility is simply commandeering the energy generated by net metered customers, selling it to non-net metered customers and pocketing the profit.

The final component of the cross-subsidization argument raises the specter of unspecified "additional costs" associated with net metering that must be recovered from all customers, not just participants. One can only speculate what these fees may entail, if not the same fixed costs we have already dealt with above. Some possibilities (application processing fees, interconnection safety, insurance and indemnification) simply constitute hidden participation fees that we have already demonstrated are unnecessary. Whatever nominal costs result from interconnecting net metered systems are far overwhelmed by the benefits net metering brings to electricity reliability, national security and the environment.[137]

135 In fact, during peak summer demand, the New York City mayor's office required large apartment units to use their generators in order to relieve system stress. (Cardwell, Diane and Zernike, Kate. (2006) City's Strategy Helped Avert Wider Con Ed Side Power Failure. New York Times. August 5.)

136 Nakarado, Gary L. (2006) Of Red Herring, Straw Men, and the Ugly Duckling Grows Up. Presented at PURPA's Net Metering Standard: Net Benefit or Net Detriment, Edison Electric Institute E-Forum. June 22.

137 Sovacool & Cooper. (2006) Green Means "Go?": The Case for an Advanced National Renewable Portfolio Standard. Electricity Journal 19:7, August/September (pp. 19-32).

If the cross-subsidization argument were true, it would justify rejecting the entire net metering program, rather than limiting system sizes with an artificial (and ineffective) "mitigation" of the problem. Limiting the size of eligible systems does not address the problems raised by cross-subsidization. Even with stringent size limits, non-participating customers would, in theory, still be subsidizing a large number of small systems instead of a small number of large systems. The size of eligible systems has little relation to the total amount of net metered energy that would be "cross-subsidized".

The lackluster participation rates in Arkansas provide a good example of how restrictions in one area (eligible system sizes), adopted in an attempt to 'balance' customer interests with the interests of the regulated community, may have the unintended consequence of destroying the entire program.

Presumably, by voting to establish a net metering program at all, the Arkansas legislature already rejected the cross-subsidization arguments raised by regulated utilities during rulemaking. However, the APSC used cross-subsidization as a justification for substantial limits to eligible system sizes and ended up adopting a cure worse than the disease. With only two residential customers and one commercial customer participating in net metering in Arkansas as of 2004, the results of Arkansas program speak for themselves. By giving deference to ill-conceived utility arguments, APSC crafted final net metering rules that effectively undermined the intention of the state legislature and did little to encourage the use of renewable energy technologies in Arkansas.

V : Best Practices

New Jersey

In the quiet New Jersey hamlet of Verona, Prout Funeral Home became the first funeral home in the northeast to install and operate a solar system that not only will power the entire operation, but will turn a profit.

The Prout story is the result of a unique combination of an enterprising mortician and the landmark restructuring of its net metering program in 2004. Since 2004, New Jersey's incentives for small-scale renewable energy, especially its generous net metering program, have been widely considered the best in the country and our analysis of 34 statewide net metering programs confirms that New Jersey's program is the most effective.[139,140]

Two simple metrics quickly confirm the success of New Jersey's approach: First, the number of net metered customers after the program was implemented; and second, the cumulative potential capacity of the small-scale renewable energy systems installed since the program was initiated. By both of these measures, New Jersey has instituted a comprehensive program that other states would be wise to emulate.

Early results indicate that New Jersey is experiencing a tremendous rate of growth in both customer participation and the cumulative capacity of installed renewable energy systems.[141] In 2004, the first year under New Jersey's restructured net metering program, the number of net metering customers in the states increased from zero to more than 300.[142] Since then, the number of solar panels in New Jersey has increased more than fivefold to 1,665.[143]

The rapid growth in customer participation can be traced to the process by which New Jersey restructured its program. By testing proposed changes against objective research and a clearly defined goal, New Jersey was able to craft net metering regulations that avoided the pitfalls bedeviling many other state programs.

Development of New Jersey's Legislation

New Jersey first adopted a net metering program in 1999. However, in 2004, New Jersey's Board of Public Utilities (BPU) ordered amendments which strengthened the program significantly. [144] Without doubt, the strength of New Jersey's new program is due largely to how it originated as part of a comprehensive strategy, including generous rebates and tax incentives, to expand renewable energy statewide.

138 Youngsworth, Jack, (20[illegible]) 'The Sun Also Rises': Funeral Home Adopts Solar Power to Lower Costs. PR Newswire US. February 22.

139 Fox, Joanne M. (2005) Net Metering in New Jersey. August 3. http://www.energypulse.net/centers/article/article_display.cfm?a_id=1065.

140 Reilly, Mike. (2005) Making Energy While the Sun Shines - Jersey's Program a Model for the Nation. The Star Ledger. August 22. p. 13.

141 While California has the highest raw numbers in either of these categories, New Jersey surpasses California in growth rate.

142 U.S. Dept. of Energy, Energy Information Agency. (2005/2006) Green Pricing and Net Metering Programs. http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/greenpricing_netmetering04.pdf http://tonto.eia.doe.gov/FTPROOT/features/gmpmreport.pdf

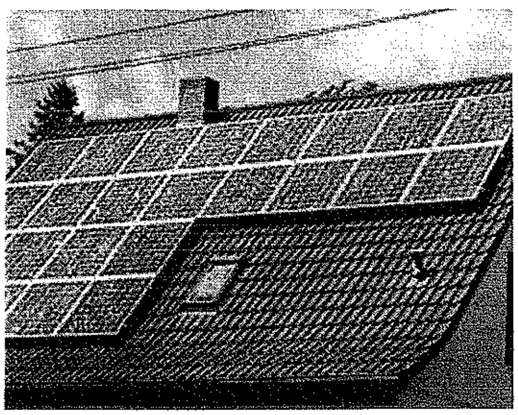
143 New Jersey's Clean Energy Program. (2006) Supported Solar Installations. August. http://www.njcep.com/html/res-installed/solar-list.html.

144 DSIRE. (2006) www.dsireusa.org.

A Foundation of Support from the Governor

Although New Jersey already had demonstrated a strong commitment to clean energy, in 2003 Governor James McGreevey created a Renewable Energy Task Force charged with making recommendations on how the state could increase its consumption of renewable energy.[145] The Task Force concluded that the state should double its requirements for renewable energy production by 2008, and also recommended a statewide goal of producing 20% of its energy from renewable sources by 2020.[146] Although the Task Force did not specifically recommend a new net metering law, the recommendations laid the foundation for significant amendments to the state's existing program.

Strong Leadership from the Commission



The Board of Public Utilities (BPU) was charged with implementing the recommendations of the Governor's Task Force. Although the Task Force had recommended a substantial increase in renewable energy generation, particularly solar, it had not specified exactly how to accomplish the increase. BPU's President, Jeanne Fox, who had also served as Task Force's chairwoman, felt that a strong net metering law was necessary to meet the Task Force goal of 20% renewable production by 2020.[147] Fox believed that it was necessary to enable customers to purchase and install larger systems than the state's previous net metering legislation if the state was to meet its renewable energy production goals. At Fox's recommendation, in 2004 the New Jersey legislature adopted a system size limit for net metered systems of 2 MW, the largest systems eligible under any existing net metering program in the nation.[148]

Focusing on Goals Rather than Consensus

Unlike many other states, New Jersey did not begin the process of amending its net metering regulations by trying to establish a consensus position with all stakeholders. A powerful Renewable Energy Task Force led by the President of the state's utility commission resulted in an approach to net metering law that kept as its focus the goal of allowing small-scale renewable energy to compete equally with conventional power.

According to drafters of the legislation, New Jersey began the process of amending the state's net metering statute by trying to determine what would attract the distributed generation (DG) industry to the state. Drafters solicited the input of utility companies, but only adopted the recommended changes when they did not compromise the primary goal of expanding the state's DG market. Changes that would have impeded the development of statewide DG industry generally were overruled.

For example, New Jersey's statue allows only residential or "small commercial customers" to participate in the state's net metering program. The precise definition of small commercial customers was critical to determining who would be eligible. A narrow definition would exclude customer classes that could provide more generation for meeting the

145 Renewable Energy Task Force. (2003) The Renewable Energy Task Force Report. Submitted to Governor James M. McGreevey. April 24. http://www.state.nj.us/bpu/reports/RenEnergyTFR.pdf

146 New Jersey Board of Public Utilities. (2003) McGreevey Receives Renewable Energy Task Force Report. September 5. http://www.state.nj.us/bpu/renewEnergy/renEnergy.shtml.

147 New Jersey Regulation Text. (2003) NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11. Proposed Rule. December 01, 2003. Board of Public Utilities. BPU Docket Number EX 03100795.

148 Ibid.

state's goal. A broader definition would allow more potential customers to participate. The bill's drafters reviewed the programs in other states and decided on a definition of "small commercial customer" as non-residential customers with less than 10MW of peak demand – a definition that was supported by the solar industry. The utilities, however, strenuously objected to this definition, and proposed a much smaller limit of 150kW.[149] Had the utilities' definition been adopted, it would have greatly reduced the number of commercial customers eligible for New Jersey's net metering program and would have artificially excluded larger generators. In the end, New Jersey's drafters rejected the utility recommendations and adopted a final rule that allowed systems up to 2MW in size to qualify as small commercial customers.[150]

Linking Net Metering to Renewable Portfolio Standards

New Jersey's amendment of its net metering program coincided with an aggressive expansion of the state's Renewable Portfolio Standard (RPS). RPS are laws that require utilities to produce a certain percentage of their power from renewable resources. New Jersey, which has had an RPS law since 1999, made changes in 2004, which required each utility serving retail customers to include 22.5% renewable energy in its electricity mix by 2021.[151]

Electricity suppliers were allowed to meet RPS requirements by investing in their own renewable energy generation or by purchasing renewable energy certificates (RECs). RECs are credited to renewable generators and represent the monetary value attached to the renewable nature of the electricity they generate. New Jersey's RPS statute issues RECs for renewable energy generated by customer-generators. However, New Jersey went a step further by allowing regulated utilities to apply RECs from customer-generators toward their RPS mandates only if those customers were also eligible for net metering. By linking net metering to the state's RPS mandates, New Jersey created an economic incentive for regulated utilities to pursue aggressive expansion of the state's net metering program. Every new net metering customer became a potential new source of renewable energy to help the utility meet its RPS requirements.

By linking net metering to the state's RPS mandates, New Jersey created an economic incentive for regulated utilities to pursue aggressive expansion of the state's net metering program. Every new net metering customer became a potential new source of renewable energy to help the utility meet its RPS requirements.

Part of a Package of Incentives

New Jersey treated its net metering program as part of a broad package of incentives designed to encourage the adoption of renewable energy.[152] Recognizing that net metering alone is not sufficient to offset the high initial costs associated with on-site renewable energy generation, New Jersey adopted a variety of rebate and tax reimbursements to reduce capital costs even further.

In addition to tax incentives, New Jersey collected a "Societal Benefits Charge" on all public utility customers and adopted a broad-based rebate program that pays renewable generators a premium on each kilowatt of electricity generated by small solar, wind

149 Ibid.

150 New Jersey Regulation Text. NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11 Adopted Rule. September 15, 2004. Board of Public Utilities. BPU Docket Number EX 03100795

151 Ibid.

152 Reilly, Mike. (2005) Making Energy While the Sun Shines - Jersey's Program a Model for the Nation. The Star Ledger. August 22. p. 13.

and sustainable biomass generators. The rebate is scaled to provide greater payment for initial kilowatts and less as generation increases. By making the rebate progressive in this way, New Jersey tilted the economic incentive to favor a larger number of small generators.

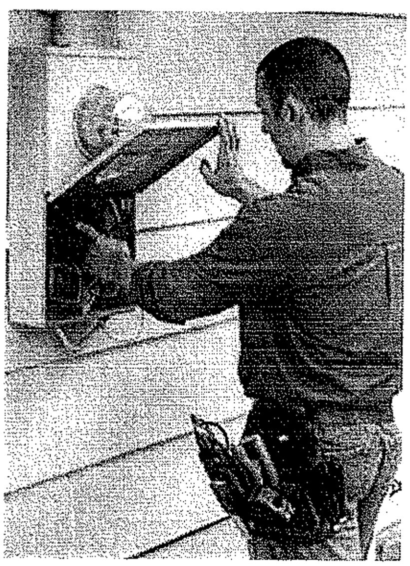
Rather than institute a number of individual state subsidies, New Jersey linked tax incentives, progressive rebates and a broad-based net metering program to create market-based inducements for investment in small-scale renewable energy.

Features of New Jersey's Program

In addition to generous system size limits, New Jersey's net metering program includes specific components that help expand both the number of participating customers and the total amount of renewable capacity that is eligible.

Streamlined Application Process

A hallmark of New Jersey's net metering program is its streamlined and transparent application process. New Jersey designed its application regulations both to overcome customer concerns about the complexity of the process and to minimize the extent to which utilities may delay applications. Prior to New Jersey amending its program, the U.S. Department of Energy released research indicating that customers who encountered major delays in application processing ultimately were discouraged from participating in net metering.[153] To address this issue, the drafters of New Jersey's statute proposed a rule requiring utilities to respond promptly to customer applications. If a utility does not approve or deny a standard residential customer's application within 20 days of having received the application, the rule considered the application approved automatically.[154] Not surprisingly, utilities objected to this proposal and requested a longer time period to review applications.[155] Ultimately, New Jersey's lawmakers rejected an extended review period and adopted the 20-day rule.



Simplified Interconnection Standards

Interconnection standards govern the manner in which customers can connect to the power grid. Effective net metering legislation is only possible if the interconnection standards enable customer-generators to connect to the grid with minimum difficulty. The New Jersey BPU understood the importance of interconnection standards to net metering and adopted model standards developed by the Interstate Renewable Energy Commission (IREC) and National Association of Regulatory Commissioners (NARUC).[156] New Jersey's standards allow all DG technologies to interconnect, do not require the customer to purchase additional insurance and impose a minimal application fee (which is waived altogether in certain cases).[157]

153 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

154 New Jersey Administrative Code. Title 14. Board of Public Utilities. Chapter 4. Energy Competition. Subchapter 9. Net Metering and Interconnection Standards For Class 1 Renewable Energy Systems N.J.A.C. 14:4-9 (2006). (14:4-9.7 (o))

155 New Jersey Regulation Text. NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11 Adopted Rule. September 15, 20[illegible]. Board of Public Utilities. BPU Docket Number EX 03100795

156 New Jersey Regulation Text. NJAC 14:4-9.1, 9.2, 9.3, 9.4 thru 9.11. Proposed Rule. December 01, 2003. Board of Public Utilities. BPU Docket Number EX 03100795.

157 Interstate Renewable Energy Council (IREC) (2006) "Connection to the Grid" Project. Interconnection Standards for Distributed Generation. June. http://www.irecusa.org/connect/state-by-state.pdf

Reduced Unnecessary Safety Requirements[158]

When New Jersey was establishing its net metering law in 2004, drafters recognized that many utilities were using safety concerns to require customers to install external disconnect switches that could be accessed easily by utility company workers. New Jersey's lawmakers suspected that the external disconnect switch might be redundant with safety mechanisms inherent in all certified inverters and feared that the requirement was acting as a disincentive to customers who wanted to install renewable energy systems.

With a grant from the nationwide Million Solar Roofs campaign, the New Jersey Public Utilities Commission contracted with Chris Cook, an expert in interconnection standards, to investigate the issue.[159] Cook thoroughly researched external disconnect switches and found that the switches were rarely, if ever, used by utility company workers and that they did almost nothing to protect the workers anyway.

The external switch requirement may even be harmful to workers both by giving them a false sense of security and by requiring them to traverse private property to access the switches.

In fact, Cook found that the external switch requirement may even be harmful to workers both by giving them a false sense of security and by requiring them to traverse private property to access the switches. In addition, the added expense of external switches created an incentive for customers to connect unauthorized systems that present a much greater safety concern to workers. An entire underground movement of illegal interconnection has sprung up in some states as a result of such requirements.[160]

In the end, New Jersey's statute prohibited utilities from requiring unnecessary and expensive additional safety equipment. Pre-tested, off-the-shelf renewable units are certified as safe and the certification removes the necessity for additional equipment. By basing its statute on a thorough investigation of utility concerns, New Jersey helped pave the way for customer-friendly interconnection standards that better protect utility industry workers.[161,162]

High System Size Limits

New Jersey allows renewable energy systems up to 2 MW to be eligible for net metering, the highest limit of any net metering legislation in the nation. A high system size limit allows non-residential customers, who have greater loads than most residencies, to participate in net metering and gives business owners an incentive to install systems capable of generating the entire on-site demand. In New Jersey, many businesses and schools have taken advantage of the 2 MW limit and installed DG systems up to the allowable limit.[163] Because these non-residential customers consume larger amounts of power, their DG systems have the added benefit of significantly reducing demand on the transmission grid while furthering New Jersey's goal of expanding statewide production of renewable energy to 20% by 2020.

158 This section is based on a Department of Energy/Million Solar Roofs publication. For more information see: National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

159 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

160 See Home Power's guerilla solar archive. http://www.homepower.com/magazine/guerrilla.cfm

161 National Renewable Energy Laboratory. (2005) Million Solar Roofs Case Study: Overcoming Net Metering and Interconnection Objections New Jersey MSR Partnership. September. http://www.nrel.gov/docs/fy05osti/38666.pdf

162 Cook, Christopher. (no date) Interconnected PV - The Utility Accessible External Disconnect Switch. www.e3energy.com/Extdisc.doc

163 New Jersey's Clean Energy Program. (2006) Supported Solar Installations. March. http://www.njcep.com/html/res-installed/solar-list.html

Broad Customer Classes

High system size limits alone are not sufficient to enable commercial classes to participate in net metering programs. As mentioned, New Jersey's statute provides an expansive definition of "small commercial customers". Without this explicit customer class, commercial customers may have been restricted and the high system size limit would be rendered largely irrelevant since most residential customer-generators would never approach 2MW of capacity. New Jersey's statue allowed no room for regulatory interpretations that would exclude larger customer-generators.

Monthly Banking of Excess Generation

Our analysis found that monthly banking of net excess generation is one of the most important factors in the effectiveness of any net metering program. For net metering customers, the grid acts like an energy bank; they deposit energy into the grid when their system produces more than they consume and withdraw energy when demand exceeds what their systems can supply. To be successful, a net metering program must facilitate banking so that customer-generators can receive credit for excess energy generated during the seasons when renewable output is highest and apply it toward their consumption when output is lower.

New Jersey's statute facilitates month-to-month banking in two ways. First, for the first 12 months of a customer's participation, the utility is required to credit customers for excess generation at the retail rate of electricity. This is important because the excess power contributed to the grid by net metered customers is sold to other consumers at the retail price. If not for monthly banking, regulated utilities would get to pocket the profits from renewable energy that they did not create. By passing those profits on to the generators of renewable energy, New Jersey's net metering program provides a strong incentive for customers to purchase systems large enough to produce an abundance of clean power. These larger systems, in turn, help reduce demand on the transmission grid and save the utility the added expense of costly additional plats that come online only during periods of peak demand.

If not for monthly banking, regulated utilities would get to pocket the profits from renewable energy that they did not create.

One potential limitation of New Jersey's program is that, at the end of the initial 12-month period, the added economic incentive created by the requirement to credit net excess generation at the retail rate disappears. From that point on, utilities are required to purchase net excess generation at the wholesale rate (or "avoided cost"). That is, no renewable energy generator can receive actual payment for excess energy at more than the wholesale rate[164]. Since the wholesale rate of electricity is generally less than the retail rate, the requirement diminishes the incentive to install systems that exceed on-site demand.

164 It is questionable whether it is even legal for states to pass legislation that would require utilities to purchase net excess generation at anything other than the avoided cost. The federal Public Utilities Regulatory Policies Act (PURPA) requires utilities to purchase electricity from qualified renewable energy facilities at the avoided cost and states that mandate any other price may be deemed in violation of PURPA. Courts have yet to settle whether states have ultimate jurisdiction to determine the rate at which net metered electricity must be purchased or if net metered customers constitute PURPA qualified facilities, in which case Congress would have to amend PURPA to allow states to set rates that exceed avoided costs.

Does not limit total capacity

Some states place a cap on the total amount of electricity that can be generated by all net metered systems (i.e. 0.1% of a utility's total capacity). This limits both the number of customers who will participate as well as the total amount of electricity produced by renewable DG systems. Placing a cap on the number of customers who can net meter is counter-productive, potentially impeding the growth of the very technologies net metering is designed to promote. New Jersey places no limit on capacity from net metering customers and has helped spark a robust DG market as a result.

Placing a cap on the number of customers who can net meter is counter-productive, potentially impeding the growth of the very technologies net metering is designed to promote.

Inclusive Definition of Eligible Technologies

One of the greatest assets of New Jersey's net metering law is its inclusive definition of eligible technologies. Solar (photovoltaic) and wind power are the two most popular distributed generation technologies for residential use, and some net metering policies include only those two technologies. New Jersey's law is inclusive of a diversity of renewable technologies (fuel cells, biomass, small hydro, landfill gas, tidal and wave energy), which is important for two reasons:

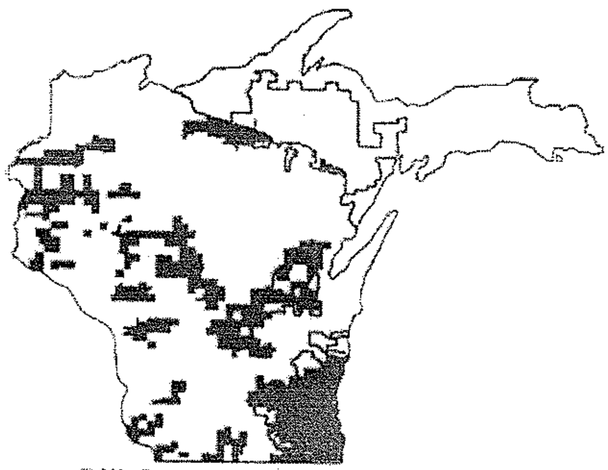
One of the most important goals of net metering is to encourage the adoption and use of distributed renewable resources. While most state programs include common renewable technologies like solar PV and wind, New Jersey's program allows fuel cells, biomass, small hydro, landfill gas and tidal and wave energy This broad definition of renewable energy helps spur the further development of novel ways of harnessing diverse renewable sources of distributed generation.

An inclusive definition of renewable energy also facilitates a more diverse net metering customer base. For example, customers involved in agriculture can use biomass, like wood pellets and switch grass, in ways that residential customers might not. It is important to include these customers in a net metering program since they use substantially more energy than residential customers and their participation can lead to more significant reductions in demand.

Regular Performance Measurements

Virtually all state-level net metering legislation incorporates some type of reporting requirement. New Jersey requires utilities to submit annual reports that include information on all customer generators in general, and net metering customers in particular. This information is valuable in judging the effectiveness of a state's net metering legislation and in determining the true costs and benefits of net metering to customers and utilities.

Rules Matter: **Michigan vs. Wisconsin**



■ We Energies: Gas Service Area
□ We Energies: Electric Service Area

Wisconsin Electric Power Company provides electric service to areas of Michigan's Upper Peninsula as well as parts of Wisconsin. This unique situation allows us to analyze two similar states that share a utility, but have vastly differing net metering policies. Both Michigan and Wisconsin have electricity rates under 10¢/kWh and their utility customers share similar demographics (see table 4.a). WE Energies, a subsidiary of Wisconsin Electric Power Co. is Wisconsin's largest energy provider and also serves Michigan's Upper Peninsula, which includes 22,000 customers in the Edison Sault Electric (another subsidiary of Wisconsin Electric) region (US Census Bureau, Wisconsin Electric Power).

Customers in the two states have the ability to interconnect with the same electric utility; however, customers in Michigan have less of an incentive to do so because of its lack of a net metering program. Michigan's program requires a $100 minimum filing fee and the state grants net excess generation (NEG) to the utility at the end of the annual billing cycle. Wisconsin's utilities, on the other hand, buy NEG at the retail rate and only charge fees on systems greater than 20kW, which is about five times greater than a typical residential customer load.

Table 4.a - Demographic comparison

State	Per capita incomes	Median income	Home own-ership rate	Electricity price
Wisconsin	**$21,271**	**$46,538**	**68.4%**	**9.988 ¢/kWh**
Michigan	**$22,168**	**$46,291**	**73.8%**	**9.313 ¢/kWh**

Data: Wisconsin Electric Power (WE Energies), US Census Bureau

Table 4.b - Net metering comparison for WE Energies customers

State	Net Metering Customers 2002	Net Metering Customers 2003	Net Metering Customers 2004	% Change in Net Metering Customers 2002-2004	Total Wisconsin Electric Customers	Number of Net Metering Customers per Million
Michigan	**4**	**3**	**4**	**0%**	**73,981**	**54.1**
Wisconsin	**70**	**74**	**79**	**13%**	**1,060,333**	**74.5**

Data: Wisconsin Electric Power (WE Energies)

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A comparison of Michigan and Wisconsin demonstrates that incentives associated with state net metering laws play a role in promoting renewable energy DG systems. Table 4.b shows that Wisconsin saw 13% growth in the rate of participation from 2002 to 2004 and has 20 times the raw number of net metering customers as Michigan.

According to Tom Stanton of Michigan's Public Service Commission (PSC), the state's current net metering provisions are simply not generous to customers.[165] On the other hand, Patrick Keily, a representative of WE Energies, believes Wisconsin customers are net metering at a higher rate because of the economic incentive provided by Wisconsin's net metering program, which requires utilities to purchase NEG at the retail rate of electricity.[166]

The differences in the two state net metering programs reflect differing goals. Michigan's policy discourages customers from installing renewable energy systems with capacities greater than on-site demand. The primary aim of Michigan's program, according to Steve Stubleski of Michigan's Consumers Energy, "is to allow customers to self- generate electricity to meet their energy needs, not become a supplier." The program is not seeking to advocate renewable energy generation, but merely to give customers the option of generating their own electricity. The program treats non-renewable DG in the same manner as renewable generation.[167]

The primary goal of Wisconsin's program, however, is expanding the use of renewable energy. The state's net metering program is part of larger state-wide initiative that priorizes energy production in the following manner:[168]

1. Energy conservation and efficiency
2. Noncombustible renewable energy resources
3. Combustible renewable energy resources
4. Nonrenewable combustible energy resources

The differing policy priorities between Michigan and Wisconsin demonstrate how net metering rules can influence customer participation and investment decisions, all other factors being equal. WE Energies customers in Michigan and Wisconsin are nearly identical, but are subject to differing net metering laws. Wisconsin has seen significant growth in participation Michigan has not.

165 Stanton, Tom. Personal Communication May 23, 2006.

166 Keily, Patrick. Personal Communication May 19, 2006.

167 Stubleski, Steve. Personal Communication. May [illegible], 2006

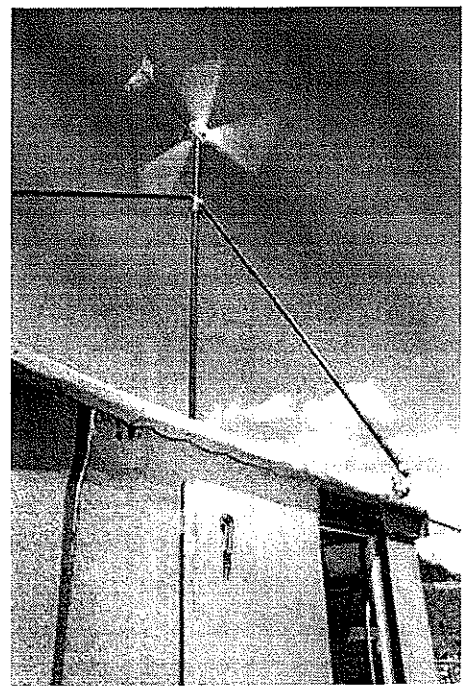
168 Wisconsin Statutes and Annotations. (2006) Chapter 1: Sovereignty and Jurisdiction of the State. 1.12(4) Priorities. http://www.legis.state.wi.us/statutes/Stat0001.pdf

VI.

How to Make Net Metering Work

Model Net Metering Statute and Regulations

Developed by the Institute for Energy & the Environment, Vermont Law School[169]



This model net metering statute and interconnection standards are applicable to all retail utilities operating within the state. The adoption of interconnection standards and regulations is delegated to the state utility regulatory commission.

In an attempt to reach a broader class of customers, the statute allows customers who generate less than 2MW of capacity to qualify for net metering. Renewable energy sources have also been defined broadly to encourage increased participation. Additional efforts to encourage participation are demonstrated through the proposed credit system. Customer-generators are allowed to "bank" excess power to the next billing period until the end of the annual billing cycle, when they are then compensated by the utility for any excess.

Retail utilities are not allowed to discourage net metering by imposing additional fees and charges that are not ordinarily charged to customers who do not participate in net metering. Utilities are also prohibited from requiring additional equipment and insurance for systems that are in compliance with accepted standards.

Program progress is tracked in an annual report compiled by the retail utility and submitted to the state utility regulatory commission. This report serves as a check on the utility to ensure that it is in compliance with the statute and is not discouraging customers from participating in net metering.

We have provided the option of including additional renewable energy sources in the definition of renewable energy. Group net metering is also encouraged because it could increase rates of participation. Group net metering allows for the cost of the renewable energy systems to be divided among a group (farm compacts, residential co-ops, etc.) so more people are able to utilize renewable energy at a decreased cost.

Educating the community about available alternatives to buying electric energy from the retail utility allows customers to make more informed decisions about their energy choices. Once more customers are aware that net metering is an available option, we believe more customers will choose self-generation as their primary electric supply.

169 In crafting these models, Vermont Law School relied, in part, on Model Net Metering Rules developed by the Interstate Renewable Energy Council in 2006 (http://www.irecusa.org/connect/netmeteringrules.pdf), FERC Order No. 2006 [18 CFR Part 35], IREC MR-I2005 Model Interconnection Standards (http://www.irecusa.org/connect/[illegible]), and model interconnection procedures from the Mid-Atlantic Distributed Resources Initiative (MADRI) and the National Association of Regulatory Utility Commissioners (NARUC).

Model Statute: The Energy Self-Reliance Act (ESRA)

Subchapter 1: Scope and Implementation

(a) This Chapter sets forth net metering requirements and interconnection standards that apply to Retail Utilities operating within the state.

(b) The state utility regulatory commission shall, after notice and opportunity for comment, adopt interconnection standards and regulations as necessary to implement this statute and promote renewable net generation (as authorized by this Chapter) throughout the state. Standards adopted pursuant to this Chapter may thereafter be amended, adopted or readopted by the state utility regulatory commission, but shall not, absent a finding of urgent public necessity, be modified so as to reduce the value of customer-generation investments upon less than 36 months prior notice.

Subchapter 2: Definitions

The following words and terms, when used in this Chapter, shall have the following meanings, unless the context clearly indicates otherwise.

"Annualized Period" means all billing periods within a single year. A customer-generator's first annualized period begins on the first day of the first full billing period after the customer-generator's facility is interconnected and is generating electricity.

"Applicant" means a person who has filed an application to interconnect a customer-generator facility to an electric delivery system.

"Customer-generator" means a residential, commercial, industrial, nonprofit, school, utility, agricultural, institutional, local government, state government, or federal government customer that generates renewable electric energy on the customer's side of the meter.

"Customer-generator Facility" means the equipment used by a customer-generator to generate, manage, and monitor electricity. A customer-generator facility includes an electric generator and/or an equipment package, as defined herein.

"Electric Delivery System" means the infrastructure constructed and maintained by a Retail Utility, as defined herein, to deliver electric service to end-users.

"Group System" means a group of physically contiguous customers located in a single electrical service provider territory that has elected to combine meters as a single billing entity in order to offset that billing against a net metered generation facility located on property owned by a group member and physically contiguous to the group members.

"Net Metering" means that the customer-generator is billed according to the difference between the amount of electricity supplied by the Retail Utility in a given billing period and the amount of electricity delivered from the customers' side of the meter using renewable energy systems, where customer-generator electricity delivered in excess of electricity supplied is credited over an annualized period.

"Renewable Electric Energy" means energy generated through the use of such resources as: (1) Solar Thermal Electricity, (2) Photovoltaic, (3) Landfill Gas, (4) Wind, (5) Biomass, (6) Hydroelectric, (7) Wave or Tidal Power, (8) Geothermal Electricity, (9) Waste-to-Energy (including Municipal Solid Waste and Agricultural Waste), (10) Fuel Cells using Renewable Fuels.

"**Retail Utility**" means any utility offering retail electric service in the State.

"**Service Entrance Capacity**" means the rating of the customer's electric service, determined by multiplying:

(1) the voltage provided to the customer by the Retail Utility

by

(2) the ampere rating of the customer's primary over-current protection device (fuse or circuit breaker)

by

(3) the appropriate multiplier for multi-phase service and generators.

Subchapter 3: Net Metering General Provisions

(a) All Retail Utilities shall offer net metering to customer-generators with renewable energy generation that are interconnected with the Retail Utility pursuant to interconnection rules adopted to implement this statute, provided that the generating capacity of the customer-generator's facility meets both of the following criteria:

1. The rated capacity of the generator does not exceed two megawatts (MW); and

2. The rated capacity of the generator does not exceed the customer's service entrance capacity.

(b) The Retail Utility shall develop a net metering tariff that provides for customer-generators to be credited, in kilowatt-hours (kWh), at a ratio of 1:1, for any production by the customer's generating facility that exceeds the customer-generator's on-site consumption of kWh. The credit shall be applied in the billing period following the billing period of excess production. However, any excess kWh credits shall not reduce any fixed billing period customer charges imposed by the Retail Utility.

(c) The Retail Utility shall carry over any excess kWh credits earned by customer-generators under paragraph (b) and apply those credits to subsequent billing periods to offset any customer-generator consumption in those billing periods. The carry over will continue until all credits are used or the end of the annual billing cycle is reached.

(d) At the end of each annual billing period, the Retail Utility shall compensate the customer-generator for any excess kWh credits at that customer-generator's otherwise applicable retail rate for marginal electric energy usage.

(e) If a customer-generator terminates its service with the Retail Utility [[*or switches electricity suppliers*]], the Retail Utility shall compensate the customer-generator for any excess kWh credits at that customer-generator's otherwise applicable retail rate for marginal electric energy usage, over the billing period immediately prior to termination of service.

(f) A customer-generator facility used for net metering shall be equipped with metering equipment that can measure the flow of electricity in both directions at the same rate. For customer-generator facilities less than 10 kilowatts (kW), this may be accomplished through use of a single, bi-directional electric revenue meter that has only a single register for billing purposes.

(g) A customer-generator may choose to use an existing electric revenue meter if the following criteria are met:

1. The meter is capable of measuring the flow of electricity both into and out of the customer generator's facility at the same rate and ratio; and

2. The meter is accurate to within plus or minus 5 percent when measuring electricity flowing from the customer-generator facility to the electric distribution system.

(h) If the customer-generator's existing electric revenue meter does not meet the requirements at (g) above, the Retail Utility shall install and maintain a new revenue meter for the customer-generator, at the Retail Utility's expense. Any subsequent revenue meter change necessitated by the customer-generator, whether because of a decision to stop net metering or for any other reason, shall be paid for by the customer-generator.

(i) The Retail Utility shall not require more than one meter per customer-generator. However, an additional meter may be installed under either of the following circumstances:

1. The Retail Utility may install an additional meter at its own expense if the customer-generator consents; or

2. The customer-generator may request that the Retail Utility install a meter, in addition to the revenue meter addressed in (g) above, at the customer-generator's expense. In such a case, the Retail Utility shall charge the customer-generator no more than the actual cost of the meter and its installation.

(j) A customer-generator owns the renewable energy credits (RECs) of the electricity it generates, and may apply to the state regulatory commission or its authorized designee for issuance of solar RECs (S-RECs) or RECs as appropriate and based on actual on-site electric generation, or the calculated estimate of on-site electric generation for generators less than 10 kW in rated capacity and as further defined in Section [[*reference any state renewable portfolio standard (RPS) requirements here*]].

(k) A Retail Utility shall provide to net-metered customer-generators electric service at non-discriminatory rates that are identical, with respect to rate structure, retail rate components, and any monthly charges, to the rates that a customer-generator would be charged if not a customer-generator.

(l) A Retail Utility shall not charge a customer-generator any fee or charge, or require additional equipment, insurance, or any other requirement not specifically authorized under this paragraph or the interconnection rules adopted to implement this statute, unless the fee, charge or other requirement would apply to other similarly situated customers who are not customer-generators.

(m) Each Retail Utility shall submit an annual net metering report to the state regulatory commission. The report shall be submitted by the end of each calendar year, and shall include the following information for the previous compliance year:

1. the total number of customer-generator facilities;

2. the total estimated rated generating capacity of its net-metered customer-generators;

3. the total estimated net kilowatt-hours received from customer-generators, expressed as both an aggregated absolute amount and, also, as a percentage of total kilowatt-hours provided to retail customers by the Retail Utility;

4. the total estimated amount of energy produced by the customer-generators; and

5. outreach and information efforts engaged in by the Retail Utility in order to inform customers about the availability of net metering service pursuant to this chapter.

Subchapter 4: Other qualifying customer-generators [[optional]]

(a) Biomass generators that run on-peak at 100% capacity and qualify for an air permit or otherwise meet criteria established by the Department of Environment.

(b) Combined heat and power (CHP) generators with efficiency greater than two times the system average (and qualifies for an air permit or otherwise meets criteria established by the Department of Environment).

(c) Group Net Metering Systems that consist of a group of physically contiguous customers located in a single electrical service provider territory that has elected to combine meters as a single billing entity in order to offset that billing against a net metered generation facility located on property owned by a group member and physically contiguous to the group members.

(d) Waste-to-Energy (including Municipal Solid Waste and Agricultural Waste).

Subchapter 5: General Provisions

(a) If a net metering interconnection has been approved under the interconnection rules of Section [*reference state interconnection rules here*], the Retail Utility shall not require a customer-generator to test or perform maintenance on its facility except for any manufacturer-recommended testing or maintenance.

(b) A Retail Utility shall have the right to inspect a customer-generator's facility during reasonable hours and with reasonable prior notice to the customer-generator. If the Retail Utility discovers that the customer-generator's facility is not in compliance with the requirements of the interconnection rules in Section [*reference state interconnection rules here*] or the requirements of IEEE Standard 1547, and the non-compliance adversely affects the safety or reliability of the Retail Utility's or other customers' facilities, the Retail Utility may require the customer-generator to disconnect the customer-generator facility until compliance is achieved.

Subchapter 6: Public Outreach and Understanding

(a) The state regulatory commission shall conduct a comprehensive statewide public outreach process regarding net metering and interconnection, [[*focused on promoting renewable electric energy*]]. The state regulatory commission shall develop and implement a public outreach and understanding process through a request for proposals that meet the following requirements:

1. provide a strong information dissemination component, in order to develop a shared foundation of credible information that may serve as a basis for engaging in meaningful dialogue;

2. engage a broad base of citizens, including those who are currently engaged in energy issues as well as those who have not yet been engaged;

3. reach throughout the state and establish a model for educating the public about the electric energy supply challenges facing the state.

Model Interconnection Standards & Regulations

Subchapter 1: Definitions

"**Area network**" means an electric delivery system served by multiple transformers interconnected in an electrical network circuit, of the type generally used in large metropolitan areas that are densely populated in order to provide high reliability of service, and having the same definition as the term "secondary grid network" as defined in IEEE standards.

"**Customer**" means a potential customer-generator that will generate renewable electric energy on the customer's side of the meter.

"**Equipment package**" means a group of components connecting an electric generator with an electric delivery system, and includes all interface equipment including switchgear, inverters, or other interface devices. An equipment package may include an integrated generator or electric source.

"**Fault current**" means electrical current that flows through a circuit and is produced by an electrical fault, such as to ground, double-phase to ground, three-phase to ground, phase-to-phase, and three-phase.

"**Good Utility Practice**" means a practice, method, policy, or action that is engaged in, and/or accepted by, a significant portion of the electric industry in a region, and that a reasonable utility official would expect, in light of the facts reasonably discernable at the time, to accomplish the desired result reliably, safely and expeditiously, but that is not inconsistent with these rules. This term has the same definition as the term is used in the interconnection rules promulgated by the FERC.

"**Group system**" means a group of physically contiguous customers located in a single electrical service provider territory, where the group has elected to combine meters as a single billing entity in order to offset that billing against a net metered generation facility located on property owned by a group member that is part of the physically contiguous properties of the rest of the group members.

"**IEEE**" means the Institute of Electrical and Electronic Engineers.

"**IEEE standards**" means the standards published by the Institute of Electrical and Electronic Engineers, available at www.ieee.org.

"**Interconnection Agreement**" means an agreement between a customer-generator and a Retail Utility, which governs the connection of the customer-generator facility to the electric delivery system, as well as the ongoing operation of the customer-generator facility after it is connected to the system. An interconnection agreement shall follow the standard form agreement developed by the state utility regulatory commission, which shall be posted on the state utility regulatory commission's website.

"**Minor System Modifications**" are those activities that entail less than 4 hours of work and not more than 5% of total system costs in materials, such as changing the fuse in a fuse holder cut-out, changing the settings on a circuit recloser, and other such activities.

"**Point of Common Coupling**" means the point in the interconnection of a customer-generator facility with an electric delivery system at which the harmonic limits are applied. This term shall have the same meaning as in IEEE Standard 1547.

"**Spot network**" means a type of electric delivery system that uses two or more inter-tied transformers to supply an electrical network circuit. A spot network is generally used to supply power to a single customer or a small group of customers and has the same meaning as the term is used in IEEE standards.

Subchapter 2: Interconnection Standards for Customer-Generator Facilities

(a) There are two interconnection review paths for interconnection of customer-sited generation.

1. Simplified – This is for qualified inverter-based facilities with a power rating of 10 kW or less on radial or spot network systems under certain conditions.

2. Standard – This is for certified generating facilities that pass certain pre-specified screens and have a power rating of 2 MegaWatts (MW) or less.

(b) In order to qualify for Simplified or Standard Interconnection Procedures, generators no larger than 2 MW must be certified pursuant to paragraph (c) to comply with the following codes and standards as applicable:

1. IEEE 1547 Standard for Interconnecting Distributed Resources with Electric Power Systems or IEEE 929 for inverters less than 10kW in size

2. UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

3. When any listed version of these codes and standards is superseded by a revision approved by the standards-making organization, then the revision will be applied under paragraph (c).

(c) Certification of Equipment Packages: Interconnection equipment shall be considered certified for interconnected operation if it has been tested and listed by a nationally recognized testing and certification laboratory (NRTL) for continuous interactive operation with a utility grid and meets the definition for Certification under FERC Order 2006.

(d) Screening Criteria for Determining Grid Impacts: A proposed interconnection that meets the following applicable screening criteria shall be processed by the Retail Utility under Standard Interconnection Procedures and, if qualified, for net metering.

1. For interconnection of a proposed generator to a radial distribution circuit, the aggregated generation, including the proposed generator, on the circuit will not exceed 15% of the total circuit annual peak load as most recently measured at the substation.

2. The proposed generator, in aggregate with other generation on the distribution circuit, will not contribute more than 10% to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of common coupling.

3. The proposed generator, in aggregate with other generation on the distribution circuit, will not cause any distribution protective devices and equipment (including but not limited to substation breakers, fuse cutouts, and line

reclosers), or customer equipment on the system, to exceed 90% of the short circuit interrupting capability; nor is an interconnection to be proposed for a circuit that already exceeds 90% of the short circuit interrupting capability.

4. The proposed generator, in aggregate with other generation interconnected to the distribution low voltage side of the substation transformer feeding the distribution circuit where the generator proposes to interconnect, will not exceed 10 MW in an area where there are known or posted transient stability limitations to generating units located in the general electrical vicinity (e.g., 3 or 4 transmission voltage level busses from the point of common coupling).

5. The proposed generator is interconnected to the Retail Utility as shown in the table below:

6. If the proposed generator is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed generator, will not exceed 20 kiloVolt-Amps (kVA).

7. If the proposed generator is single-phase and is to be interconnected on a transformer center tap neutral of a 240 volt service, its addition will not create an imbalance between the two sides of the 240 volt service of more than 20% of nameplate rating of the service transformer.

8. The proposed generator's Point of Common Coupling will not be on a transmission line.

Primary Distribution Line Configuration	Interconnection to Primary Distribution Line
Three-phase, three wire	If a 3-phase or single phase generator, interconnection must be phase-to-phase
Three-phase, four wire	If a 3 phase (effectively grounded) or single-phase generator, interconnection must be line-to-neutral

(e) Special Screening Criteria for interconnection to Spot Networks and Area Networks. The Screening Criteria under this paragraph shall be in addition to the applicable Screens in paragraph (d).

1. For interconnection of a proposed generator to a spot network circuit where the generator or aggregate of total generation exceeds 5% of the spot network's maximum load, the generator must utilize a protective scheme that will ensure that its current flow will not affect the network protective devices including reverse power relays or a comparable function.

2. For interconnection of a proposed generator that utilizes inverter based protective functions to an area network, the generator, in aggregate with other exporting generators interconnected on the load side of network protective devices, will not exceed the lesser of 10% of the minimum annual load on the network or 500 kW. For a solar photovoltaic customer-generator facility, the 10% minimum shall be determined as a function of the minimum load occurring during an off-peak daylight period

3. For interconnection of generators to area networks that do not utilize inverter based protective functions or inverter based generators that do not meet the requirements of subparagraph (e)(2) above, the generator must utilize reverse power relays or other protection devices to ensure that there will be no export of power from the customer's site, including any inadvertent export (under fault conditions) that could adversely affect protective devices on the network circuit.

(f) Each Retail Utility shall have a Simplified Interconnection Procedure for Inverter Based Generators not exceeding 10kW in capacity, which shall require the following steps.

1. The customer submits an application, filled out properly and completely, indicating which certified generator or equipment package the customer intends to use.

2. The Retail Utility acknowledges to the customer receipt of the application within 3 business days of receipt.

3. The Retail Utility evaluates the application for completeness and notifies the customer within 7 business days of acknowledgement of receipt that the application is or is not complete, and whether the generating facility equipment passes screens 1, 6, 7 and 8 in paragraph (d). If incomplete, or if the generating facility equipment does not pass the appropriate screens, the application is rejected and returned to the customer with a list of items needed to make it complete.

4. If the application is complete, and the generating facility equipment passes the applicable screens, then within 3 business days of the customer notification under subparagraph (f)(3), the Retail Utility will execute and send a Simplified Interconnection Agreement to customer.

5. If the Retail Utility does not notify a customer in writing or by e-mail whether the interconnection is approved or denied within 20 business days after the receipt of an application, the interconnection shall be deemed approved. The 20 days shall begin on the date that the Retail Utility sends the written or e-mail notice that the application is received.

6. Upon receipt of the signed Simplified Interconnection Agreement and completion of installation, the Retail Utility may inspect the generating facility for compliance with standards and may arrange for a witness test.

7. Provided the inspection/test is satisfactory, the Retail Utility must notify the customer, in writing, within 15 business days that interconnection is allowed, and approved. If the inspection/test is unsatisfactory, the Retail Utility must notify the customer, in writing, within 15 business days, explaining the reasons for disapproval of interconnection. Final interconnection of the generator is subject to approval by the appropriate electrical code officials.

8. The Simplified Interconnection is provided at no cost to the customer. Additional protection equipment not included with the certified generator or interconnection equipment package may be added at the Retail Utility's discretion as long as the performance of the system is not negatively impacted

in any way and the customer is not charged for any equipment in addition to that which is included in the certified equipment package.

(g) Each Retail Utility shall have a Standard Interconnection Procedure for customer-sited generators not subject to paragraph (f) above and not exceeding 2 MW in capacity that will use existing customer facilities, which shall require the following steps.

1. To assist customers in the interconnection process, the Retail Utility will designate an employee or office from which basic information on the application can be obtained through an informal process. On request, the Retail Utility will provide the customer with all relevant forms, documents, and technical requirements for filing a complete application for interconnection of generators not exceeding 2 MW to the Retail Utility's electric power system. Upon the customer's request, the Retail Utility will meet with the customer prior to submission of an application for Standard Interconnection.

2. The customer shall submit an application for Standard Interconnection to the Retail Utility and may, at the same time, submit an Interconnection Agreement executed by the customer.

3. The customer will be notified by the Retail Utility within 3 business days of its receipt of an interconnection application.

4. The Retail Utility will notify the customer within 7 business days of acknowledgement of receipt of the application whether it is complete or incomplete. If the application is incomplete, the Retail Utility will at the same time provide the customer a written list detailing all information that must be provided to complete the application. The customer will have 10 business days to submit the listed information following receipt of the notice. If the customer does not submit the listed information to the Retail Utility within the 10 business days, the application shall be deemed withdrawn. An application will be complete upon the customer's submission of the information identified in the Retail Utility's written list.

5. Within 10 business days after the Retail Utility notifies customer it received a complete application, the Retail Utility shall perform an Initial Review of the proposed interconnection, which shall consist of an application of the screening criteria set forth in paragraphs (d) and (e). The Retail Utility shall notify customer of the results, providing copies of the analysis and data underlying the Retail Utility's determinations under the screens. During the Initial Review, the Retail Utility may conduct, at its own expense, any additional studies or tests it deems necessary to evaluate the proposed interconnection.

6. If the Initial Review determines that the proposed interconnection passes the screens set forth in paragraphs (d) and (e) as applicable, the interconnection application will be approved and the Retail Utility will provide the customer with an executable Interconnection Agreement within 5 business days after the determination.

7. If the Initial Review determines that the proposed interconnection fails one or more screens in paragraphs (d) and (e), but the Retail Utility determines through the Initial Review that the small generator may nevertheless be interconnected consistent with safety, reliability, and power quality, with or without minor system modifications, the Retail Utility will provide the customer with an executable Interconnection Agreement within 5 business days after the determination. The generator is responsible for the cost of any minor system modifications required.

8. If the Initial Review determines that the proposed interconnection fails one or more screens in paragraphs (d) and (e), and the Retail Utility does not or cannot determine from the Initial Review that the generator may nevertheless be interconnected consistent with safety, reliability, and power quality standards, then the Retail Utility will offer to perform an additional review if the Retail Utility concludes that additional review might determine that the generator could qualify for interconnection pursuant to the Standard Procedures. The Retail Utility will provide a non-binding, but good faith estimate of the costs of such additional review when it notifies the customer that its proposed interconnection has failed one or more screens in paragraphs (d) and (e).

9. Each Retail Utility will include in its net metering and interconnection compliance tariff the procedure it will follow for any additional review including the allocation of cost responsibility to the customer.

10. Final interconnection of the customer's generator is subject to commissioning tests as set forth in the IEEE standard 1547 (paragraph (b)) and approval by the appropriate local electrical code officials.

11. An application and processing fee may be imposed on customers proposing interconnection of generators under Standard Interconnection Procedures provided the total of all fees to complete the interconnection does not exceed $50 plus $1.00 per kilowatt of the capacity of the proposed generator. Additional fees may only be charged to customers if their generator interconnection requires minor system modifications pursuant to subparagraph (g)(7) or additional review pursuant to subparagraph (g)(8). Costs for minor system modifications or additional review will be based on quotations for services from the Retail Utility and subject to review by the state utility regulatory commission or its designee for such review.

(h) An electric distribution company may not require a customer-generator whose system(s) meets the Simplified or Standard Interconnection standards in paragraphs (b) through (g) above, as applicable, to install additional controls, perform or pay for additional tests or purchase additional liability insurance, except as agreed to by the customer in paragraph (g) above.

(i) Each customer-generator approved for interconnection shall affix to their electric revenue meter a standard warning sign as approved by the state utility regulatory commission that notifies utility personnel of the existence of customer-sited parallel generation.

Subchapter 3: Miscellaneous

(a) A Retail Utility that charges a fee for an interconnection study shall provide the customer-generator with a bill that includes a clear explanation of all charges. In addition, the Retail Utility shall provide to the customer-generator, prior to the start of the interconnection study, a good faith estimate of the number of hours that will be needed to complete the interconnection study, and an estimate of the total interconnection study fee.

(b) If a customer-generator's facility complies with all applicable standards in subchapter 2, the facility shall be presumed to comply with the technical requirements of this paragraph. In such a case, the Retail Utility shall not require a customer-generator to install additional controls (including but not limited to a utility accessible disconnect switch), perform or pay for additional tests, or purchase additional liability insurance in order to obtain approval to interconnect.

(c) Once an interconnection has been approved under this paragraph, the Retail Utility shall not require a customer-generator to test its facility except that it may require the following:

1. an annual test in which the customer-generator's facility is disconnected from the Retail Utility's equipment to ensure that the generator stops delivering power to the grid;

2. any manufacturer-recommended testing; and

3. a test to verify continued interconnection after a power outage.

(d) A Retail Utility shall have the right to inspect a customer-generator's facility both before and after interconnection approval is granted, at reasonable hours and with reasonable prior notice to the customer-generator. If the Retail Utility discovers the customer-generator's facility is not in compliance with the requirements of subchapter 2 and the non-compliance adversely affects the safety or reliability of the electric system, the Retail Utility may require disconnection of the customer-generator's facility until it complies with this paragraph.

Subchapter 4: Group Net Metering [[*optional*]]

(a) Electric energy measurement for net metering systems using a group system shall be calculated in the following manner:

1. Net metering customers that are group systems may credit all on-site generation against all meters designated to the group system.

2. If the electricity generated by the group system is less than the total usage of all meters included in the system during the billing period, the customer shall be credited for any accumulated kWh credit and then billed for the net electricity supplied by the electric utility.

(b) [[*In addition to any other requirements of an applicable state statute*]], before a group system including more than one meter may be formed and served by a Retail Utility, the group system shall file with the state utility regulatory commission and the serving Retail Utility, the following information:

1. the meters to be included in the group system, which shall be associated with buildings and residences owned or occupied by the person operating the group system, identified by the most relevant pre-existing account number and location or, if no such account number exists, by location and proposed point of interconnection to the utility system

2. a method for adding and removing meters included in the group system;

3. a designated person responsible for all communications from the group system to the Retail Utility, for receiving and paying bills for any services provided by the Retail Utility for the group system, and for receiving any other communications regarding the group system; and

4. a binding process for the resolution of any disputes within the group system relating to net metering that does not rely on the Retail Utility or the state utility regulatory commission.

(c) Group system customers shall, at all times, maintain a written designation to the Retail Utility of a person who shall be the sole person authorized to receive and pay bills for service provided by the Retail Utility, and for any other communications regarding the group system.

(d) The Retail Utility shall implement appropriate changes to a group system within thirty days after receiving written notification from the person designated under subchapter 4, paragraph (c). However, written notification of a change in the person designated under subchapter 4, paragraph (c) shall be effective upon receipt by the Retail Utility. The Retail Utility shall not be liable for action based on such notification, but shall make any necessary corrections and bill adjustments to implement revised notifications.

(e) In cases of non-payment of group system bills, the electric utility may disconnect all meters associated with the group system [[*in accordance with the same state utility regulatory commission rules as are applicable to the most nearly analogous customers without netmetering*]].

Subchapter 5: Dispute Resolution

(a) The state utility regulatory commission may from time to time designate a hearing officer or technical master for the resolution of interconnection disputes. If the state utility regulatory commission has so designated, the parties shall use the hearing officer or technical master to resolve disputes related to interconnection and such resolution shall be binding on the parties.

(b) The state utility regulatory commission may designate a Department of Energy national laboratory, college or university, or an approved Federal Energy Regulatory Commission (FERC) Regional Transmission Office with distribution system engineering expertise as the technical master. Should the FERC identify a national technical dispute resolution team, the state utility regulatory commission may designate said team as its hearing officer or technical master.

000345

A Federal Net Metering Program

While individual states can and should improve their net metering programs by adopting the model statutes we have recommended, the wide discrepancy in both the design and implementation of individual state net metering programs has created an uneven playing-field, both for regulated utilities and for small-scale renewable generating facilities. Ideally, a uniform national renewable energy policy would stem from federal leadership. Unifying the country behind the important goal of increasing renewable energy output could be achieved with a cleverly-designed national net metering policy that standardizes net metering procedures and overcomes the limitations often created by a patchwork of state-based initiatives.

Our analysis of 34 existing state net metering programs reveals that most utilities are likely to embrace changes in net metering mandates with the enthusiasm of a tax audit[170]. Because most utilities perceive net metering programs as revenue-losers rather than demand-reduction strategies, they have lobbied at the state level for unnecessary restrictions, burdensome procedures and excessive fees that limit participation.[171] As we have shown, in many states the regulatory barriers established at the behest of utilities have effectively thwarted the original intentions of the net metering programs.

Individual states that have been the most effective at promoting clean energy have treated net metering as a demand-reduction strategy that is part of a broad system of incentives to encourage the adoption of renewable energy technologies. Because renewable systems typically produce the most electricity during hours of peak demand (solar panels, for instance, generate the most electricity in the afternoon, when demand on the grid is greatest), net metered customers generally consume electricity from the grid during off-peak hours. Therefore, net metering should be perceived as a benefit to regulated utilities by reducing peak demand at the times when the grid is most strained.

A novel way to create the perception among utilities that net metering is an effective demand-reduction strategy is to establish a national renewable portfolio standard (RPS) that requires by a date certain that all regulated utilities meet a percentage of net electricity demand through qualified renewable resources. For example, a national RPS statute might mandate that by 2020, all regulated utilities are required to meet 20% of net electricity demand from electricity generated by qualified renewable sources. This approach sets the renewable energy goal as a function of electricity *demand* rather than electricity *generation*.[172]

Calculating RPS goals as a function of electricity demand provides utilities with additional flexibility that some state RPS architectures do not. By making the national RPS goal a function of demand, the ultimate compliance level is placed squarely in the hands of utilities, encouraging them to view on-site renewable generation as a demand

170 When New York recently solicited comments pursuant to its consideration of the state's net metering program as required by EPAct, regulated utilities almost universally commented that no additional expansion was warranted.

171 Graves, F. (2006) Net Metering Under EPAct 2005: Setting Customer Credits and Related Issues. Presented at PURPA's Net Metering Standard: Net Benefit or Net Detriment, Edison Electric Institute E-Forum, June 22.

172 NNEC Executive Director Chris Cooper and Board Member Dr. Benjamin Sovacool first proposed this idea in a recent Electricity Journal article that provides greater detail. See Sovacool, B. and Cooper, C. (2006) Green Means 'Go?': A Colorful Approach to a U.S. National Renewable Portfolio Standard. Electricity Journal. 19:7. August/September (pp. 19-32).

reduction strategy that helps them meet their regulatory requirements. Every reduction in demand also reduces the total amount of renewable energy that utilities are required to generate on their own. By creating a regulatory framework where utilities view net metering programs correctly as demand-reduction strategies, a national RPS would promote increased participation in net metering programs and encourage utilities to support higher capacity caps, expand the number of eligible customer classes, and decrease the unnecessary regulatory burdens that have tended to discouraged participation in many states.

A national program provides a level of regulatory predictability that should be embraced by the growing number of utilities operating across states that are required to develop net metering programs.

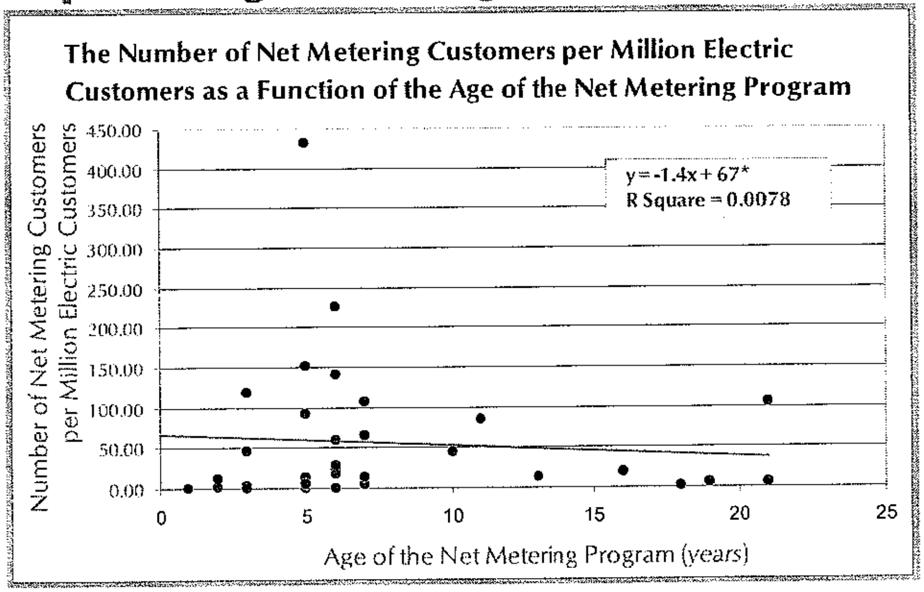
For the renewable energy services sector, a national net metering scheme would allow market forces to dictate the geography of energy investments. A national strategy would allow certain technologies to flourish where they are most useful and encourage a greater diversity of electricity generation across states.

Standardized national net metering rules would also create a uniform curriculum for training technicians and create a more diverse pool of expertise that would reduce the amount of time (and money) individual states spend developing their own curriculums and training their own technicians. National standards would also expand job opportunities for certified technicians by allowing greater employment mobility. Expertise developed in one state would be just as useful in any other state.

For utilities, a uniform, federal net metering program should prove more attractive than a network of 50 state-based regulatory schemes. A national program provides a level of regulatory predictability that should be embraced by the growing number of utilities operating across states that have yet to develop net metering programs as required by EPAct. Even for utilities focused exclusively on the bottom line, the devil you know is better than the devil you don't.

Appendix A

Explaining the Magic Number 67



Data: DOE EIA, DOE EERE, and Union of Concerned Scientists[173]

Appendix A is a regression comparing the number of net metering customers with the age of the net metering statute. The most recent available customer data is from 2004 and therefore we based the age of the statute on a 2004 starting point. We determined that California, with over 13,000 net metering customers, is an outlier and not included in this analysis.

The results of the regression show that, although the equation is negative, there is not a significant change in the number of net metering customers over the course of time ($p = 0.63$). Although the slope of the line is not significant, we can infer that newer net metering programs tend to have more customers when compared to older ones.

The Y intercept - 67 - is significant ($p = 0.017$), which means that we have confidence that any net metering program, no matter its age, should have at least 67 customers. Therefore, we characterize effective state net metering programs as having at least 67 customers enrolled. Based on this analysis, we expect new state programs to have enrollment numbers of this size.

173 Energy Information Agency. Green Pricing and Net Metering Programs 2004. March 2006. http://www.eia.doe.gov/cneaf/solar.renewables/page/greenprice/green_pricing.html

Union of Concerned Scientists. Summary of State "Net Metering" Programs. April 2006. http://www.ucsusa.org/assets/documents/clean_energy/State_Net_Metering_Rules.pdf

U. S. Dept. of Energy, Office of Energy Efficiency and Renewable Energy. July 12, 2004 http://www.eere.energy.gov/greenpower/pdfs/metering_0604.pdf

Breaking Ties

The table below lists the reasons for breaking ties between states that have the same index score. Most ties were broken by evaluating the rate of growth in participation or the total number of participating customers.

Rank	State	Grade	Percentile	Score	Reason for Higher Ranking
1	New Jersey	A	100%	305	
2	Montana	A	97%	67	
3	California	A	94%	15	
4	Oregon	A	91%	14	
5	Nevada	A	88%	7	
6	Minnesota	A	82%	6	Greater growth rate
7	New Hampshire	A	82%	6	
8	Wisconsin	A	79%	4	
9	Hawaii	B	64%	3	Greater growth rate
10	Vermont	B	64%	3	More participating customers per capita
11	Wyoming	B	64%	3	More participating customers per capita
12	Ohio	B	64%	3	More participating customers per capita
13	Louisiana	B	64%	3	
14	Utah	B	61%	2	
15	Connecticut	C	48%	1	More participating customers per capita
16	New York	C	48%	1	More participating customers per capita
17	New Mexico	C	48%	1	More participating customers per capita
18	Georgia	C	48%	1	
19	Washington	D	36%	0	More participating customers per capita
20	Virginia	D	36%	0	More participating customers per capita
21	Kentucky	D	36%	0	Has participating customers
22	Maine	D	36%	0	
23	Massachusetts	F	27%	-1	More participating customers per capita
24	Iowa	F	27%	-1	Has participating customers
25	Delaware	F	27%	-1	
26	Colorado	F	9%	-2	More participating customers per capita
27	North Dakota	F	9%	-2	More participating customers per capita
28	Indiana	F	9%	-2	More participating customers per capita
29	Maryland	F	9%	-2	More participating customers per capita
30	Texas	F	9%	-2	Net excess generation purchased, not granted, by the utility monthly
31	Arkansas	F	9%	-2	
32	Rhode Island	F	3%	-3	More participating customers per capita
33	Pennsylvania	F	3%	-3	
34	Oklahoma	F	0%	-4	

Glossary of Terms

DG – Distributed Generation

Also known as 'Community-Based Power', distributed generation is Electricity generation that occurs at or near the site of ultimate consumption as opposed to most electricity which is generated at a remote site and transported by long-distance transmission lines to the consumer.

EIA – Energy Information Administration (Department of Energy)

The Energy Information Administration (EIA), as part of the U.S. Department of Energy, collects and disseminates data on energy reserves, production, consumption, distribution, prices, technology, and related international, economic, and financial matters. Coverage of EIA's programs includes data on coal, petroleum, natural gas, electric, and nuclear energy.

EPAct – Energy Policy Act of 2005

Also know as 'The Energy Bill, EPAct was intended to establish a comprehensive, long-range energy policy. It provides incentives for traditional energy production as well as newer, more efficient energy technologies, and conservation. More than 1,700 pages long, the Act has hundreds of provisions affecting energy generation and utility policy.

FERC – Federal Energy Regulatory Commission

An independent federal agency, FERC regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects.

IEEE1547 – Institute of Electrical and Electronics Engineers standard

IEEE 1547 is the Institute's standard for interconnecting distributed resources (DG systems) with electric power systems and was approved by the IEEE Standards Board in June 2003. It was approved as an American National Standard in October 2003.

NEG – Net Excess Generation

When a net metered customer produces more electricity than it consumes during a utility billing cycle, the difference is called the net excess generation.

PUHCA – Public Utility Holdings Company Act of 1935

A 'New Deal' law to protect consumers and investors. It placed geographic restrictions on mergers and limitations on diversification into non-utility lines of business and takeovers of electric and gas utilities, and also established regulated monopoly markets or service territories for utilities.

PURPA – Public Utility Regulatory Policies Act of 1978

PURPA was passed during the 1970's energy crisis to encourage the conservation and efficient use of energy resources and to encourage the development of alternative power supplies capable of displacing the inefficient use of oil and natural gas by electric utilities. PURPA requires electric utilities, when they need power, to purchase power from qualifying alternative energy facilities (QFs) at the utilities' avoided cost, provide back-up power to QFs, interconnect with QFs, and operate with QFs under reasonable terms and conditions.

PV – Photovoltaic

Photovoltaics (PV) or solar cells as they are often called, are semiconductor devices that convert sunlight into direct current (DC) electricity. Groups of PV cells are electrically configured into modules and arrays, which can be used to charge batteries, operate motors, and to power any number of electrical loads. With the appropriate power conversion equipment, PV systems can produce alternating current (AC) compatible with any conventional appliances, and can operate in parallel with, and interconnected to, the utility grid.

RECs – Renewable Energy Credits

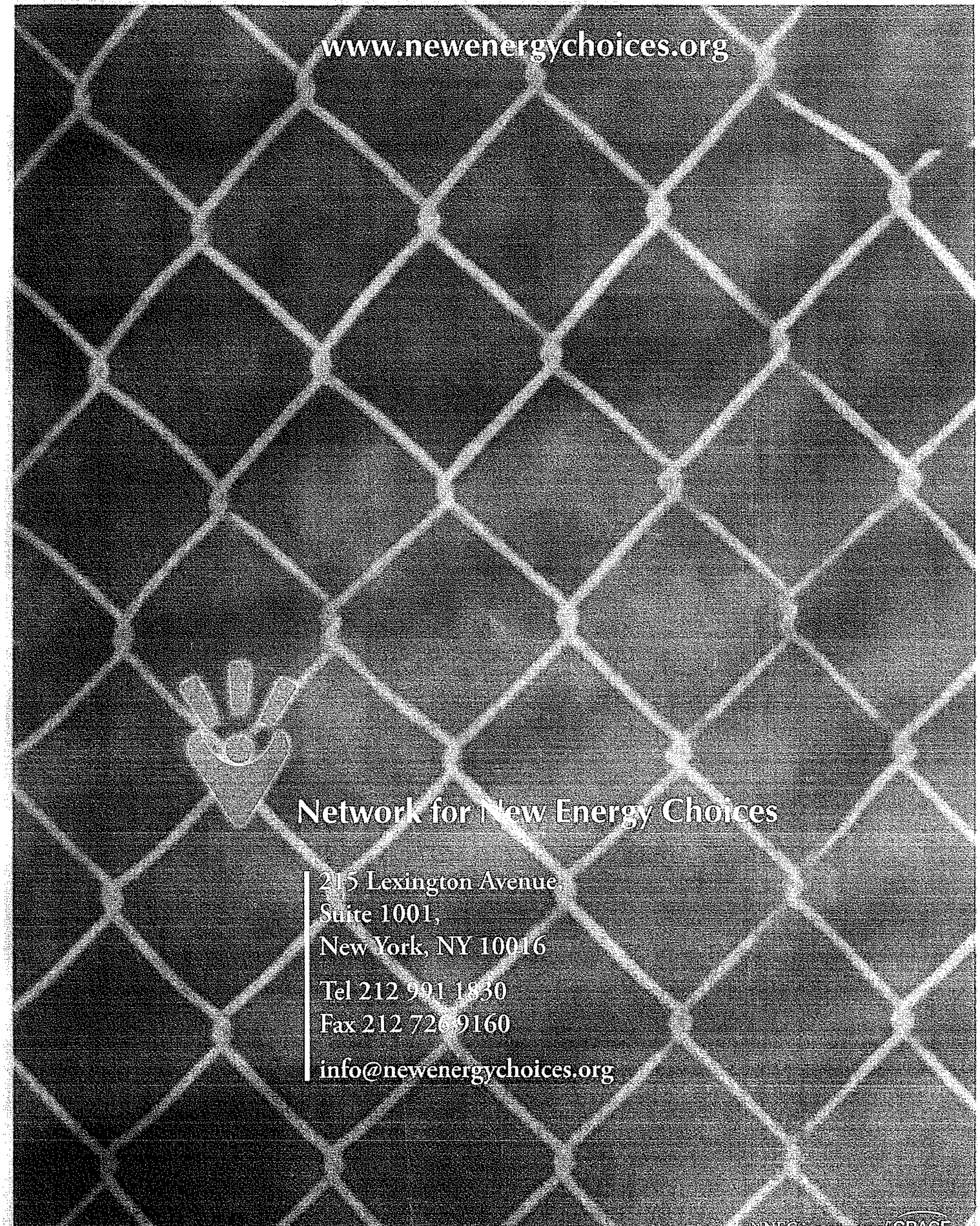
Also known as Green Tags or Tradable Renewable Certificates (TRCs), RECs represent the environmental benefits associated with generating electricity from renewable energy sources. RECs function as a non-governmental subsidy on pollution-free electricity generators. Within REC trading markets, a certifying agency gives each REC a unique identification number to make sure it doesn't get double-counted. The clean energy is then fed into the electrical grid and the accompanying REC can then be sold separately from the electricity.

RPS – Renewable Portfolio Standards

A policy set by federal or state governments that a percentage of the electricity supplied by generators be derived from a renewable source by a date certain.

T&D – Transmission & Distribution

Electric power transmission is one process in the transmitting of **electricity** to consumers. The term refers to the bulk transfer of electrical power from place to place. Typically, power transmission is between the **power plant** and a **substation** near a populated area. This is distinct from **electricity distribution**, which is concerned with the delivery from the substation to the consumers. Due to the large amount of power involved, transmission normally takes place at high voltage (110 kV or above). Electricity is usually transmitted over long distance through overhead power transmission lines (such as those in the photo on the right). Underground power transmission is used only in densely populated areas (such as large cities) because of the high cost of installation and maintenance.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THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION

A STUDY PURSUANT TO SECTION 1817 OF THE ENERGY POLICY ACT OF 2005

February 2007

U.S. Department of Energy

EPAct 2005 SEC. 1817. STUDY OF DISTRIBUTED GENERATION.

(a) Study-

(1) IN GENERAL-

(A) POTENTIAL BENEFITS- The Secretary, in consultation with the Federal Energy Regulatory Commission, shall conduct a study of the potential benefits of cogeneration and small power production.

(B) RECIPIENTS- The benefits described in subparagraph (A) include benefits that are received directly or indirectly by--

(i) an electricity distribution or transmission service provider;

(ii) other customers served by an electricity distribution or transmission service provider; and

(iii) the general public in the area served by the public utility in which the cogenerator or small power producer is located.

(2) INCLUSIONS- The study shall include an analysis of--

(A) the potential benefits of--

(i) increased system reliability;

(ii) improved power quality;

(iii) the provision of ancillary services;

(iv) reduction of peak power requirements through onsite generation;

(v) the provision of reactive power or volt-ampere reactives;

(vi) an emergency supply of power;

(vii) offsets to investments in generation, transmission, or distribution facilities that would otherwise be recovered through rates;

(viii) diminished land use effects and right-of-way acquisition costs; and

(ix) reducing the vulnerability of a system to terrorism; and

(B) any rate-related issue that may impede or otherwise discourage the expansion of cogeneration and small power production facilities, including a review of whether rates, rules, or other requirements imposed on the facilities are comparable to rates imposed on customers of the same class that do not have cogeneration or small power production.

(3) VALUATION OF BENEFITS- In carrying out the study, the Secretary shall determine an appropriate method of valuing potential benefits under varying circumstances for individual cogeneration or small power production units.

(b) Report- Not later than 18 months after the date of enactment of this Act, the Secretary shall--

(1) complete the study;

(2) provide an opportunity for public comment on the results of the study; and

(3) submit to the President and Congress a report describing--

(A) the results of the study; and

(B) information relating to the public comments received under paragraph (2).

(c) Publication- After submission of the report under subsection (b) to the President and Congress, the Secretary shall publish the report.

THE POTENTIAL BENEFITS OF DISTRIBUTED GENERATION AND RATE-RELATED ISSUES THAT MAY IMPEDE THEIR EXPANSION

A STUDY PURSUANT TO SECTION 1817 OF THE ENERGY POLICY ACT OF 2005

February 2007

U.S. Department of Energy

Executive Summary

Background

Section 1817 of the Energy Policy Act (EPACT) of 2005, calls for the Secretary of Energy to conduct a study of the potential benefits of cogeneration and small power production, otherwise known as distributed generation, or DG. The benefits to be studied include those received "either directly or indirectly by an electricity distribution or transmission service provider, other customers served by an electricity distribution or transmission service provider and/or the general public in the area served by the public utility in which the cogenerator or small power producer is located." Congress did not require the study to include the potential benefits to owners/operators of DG units.

The specific areas of potential benefits covered in this study include:

- Increased electric system reliability (Section 2)
- Reduction of peak power requirements (Section 3)
- Provision of ancillary services, including reactive power (Section 4)
- Improvements in power quality (Section 5)
- Reductions in land-use effects and rights-of-way acquisition costs (Section 6)
- Reduction in vulnerability to terrorism and improvements in infrastructure resilience (Section 7)

Additionally, Congress requested an analysis of "...any rate-related issue that may impede or otherwise discourage the expansion of cogeneration and small power production facilities, including a review of whether rates, rules, or other requirements imposed on the facilities are comparable to rates imposed on customers of the same class that do not have cogeneration or small power production." The results of this analysis are presented in Section 8.

A Brief History of DG

DG is not a new phenomenon. Prior to the advent of alternating current and large-scale steam turbines - during the initial phase of the electric power industry in the early 20th century - all energy requirements, including heating, cooling, lighting, and motive power, were supplied at or near their point of use. Technical advances, economies of scale in power production and delivery, the expanding role of electricity in American life, and its concomitant regulation as a public utility, all gradually converged to enable the network of gigawatt-scale thermal power plants located far from urban centers that we know today, with high-voltage transmission and lower voltage distribution lines carrying electricity to virtually every business, facility, and home in the country.

At the same time this system of central generation was evolving, some customers found it economically advantageous to install and operate their own electric power and thermal energy systems, particularly in the industrial sector. Moreover, facilities with needs for highly reliable power, such as hospitals and telecommunications centers, frequently installed their own electric generation units to use for emergency power during outages. These "traditional" forms of DG, while not assets under the control of electric utilities, produced benefits to the overall electric system by providing services to consumers that the utility did not need to provide, thus freeing up assets to extend the reach of utility services and promote more extensive electrification.

Over the years, the technologies for both central generation and DG improved by becoming more efficient and less costly. Implementation of Section 210 of the Public Utilities Regulatory Policy Act of 1978 (PURPA) sparked a new era of highly energy efficient and renewable DG for electric system applications. Section 210 established a new class of non-utility generators called "Qualifying Facilities" (QFs) and provided financial incentives to encourage development of cogeneration and small power production. Many QFs have since provided energy to consumers on-site, but some have sold power at rates and under terms and conditions that have been either negotiated or set by state regulatory authorities or nonregulated utilities.

Today, advances in new materials and designs for photovoltaic panels, microturbines, reciprocating engines, thermally-activated devices, fuel cells, digital controls, and remote monitoring equipment, among other components and technologies, have expanded the range of opportunities and applications for "modern" DG, and have made it possible to tailor energy systems that meet the specific needs of consumers. These technical advances, combined with changing consumer needs, and the restructuring of wholesale and retail markets for electric power, have opened even more opportunities for consumers to use DG to meet their own energy needs, as well as for electric utilities to explore possibilities to meet electric system needs with distributed generation.

Public Input

Wherever possible, this study utilizes existing information in the public domain, including, for example, published case studies, reports, peer-reviewed articles, state public utility commission proceedings, and submitted testimony. No new analysis tools have been explicitly created for this study; nor have findings in this report been prepared in isolation from the body of materials produced by DG practitioners and others over the past decade.

A *Federal Register* Notice published in January, 2006[1] requested all interested parties to submit case studies or other documented information concerning DG as it relates to EPACT 1817. Forty-one organizations responded with studies, reports, data, and suggestions. The U.S. Department of Energy (DOE) has reviewed all of this information and is grateful to those individuals and organizations that provided data, reports, comments, and suggestions.

Major Findings

- Distributed generation is currently part of the U.S. energy system. There are about 12 million DG units installed across the country, with a total capacity of about 200 GW. Most of these are back-up power units and are used primarily by customers to provide emergency power during times when grid-connected power is unavailable. This DG capacity also includes about 84 GW[2] of consumer-owned combined heat and power systems, which provide electricity and thermal

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1 71 FR 4904- 4905.. "Study of the Potential Benefits of Distributed Generation," January 30, 2006.

2 Paul Bautista, Patti Garland, and Bruce Hedman, *2006 Action Plan, Positioning CHP Value: Solutions for National, Regional, and Local Energy Issues,* Presented at 7th National CHP Roadmap Workshop, Seattle, Washington, September 13, 2006.

energy for certain manufacturing plants, commercial buildings, and independently-owned district energy systems that provide electricity and/or thermal energy for university campuses and urban areas. While many electric utilities have evaluated the costs and benefits of DG, only a small fraction of the DG units in service are used for the purpose of providing benefits to electric system planning and operations.

- There are several economic and institutional reasons why electric utilities have not installed much DG. For example, the economics of DG are such that financial attractiveness is largely determined on a case-by-case basis, and is very site-specific. As a result, many of the potential benefits are most easily captured by customers so that the incentives for customer-owned DG are often far greater than those for utility-owned DG. This has led to the current situation where standard business model(s) for electric utilities to invest profitably in DG have not emerged. In addition, in instances where financially attractive DG opportunities for electric utilities have been identified, there is often a lack of familiarity with DG technologies, which has contributed to the perception of added risks and uncertainties, particularly when DG is compared to conventional energy solutions. This lack of familiarity has also contributed to a lack of standard data, models, or analysis tools for evaluating DG, or standard practices for incorporating DG into electric system planning and operations.
- Nevertheless, DG offers potential benefits to electric system planning and operations. On a local basis there are opportunities for electric utilities to use DG to reduce peak loads, to provide ancillary services such as reactive power and voltage support, and to improve power quality. Using DG to meet these local system needs can add up to improvements in overall electric system reliability. For example, several utilities have programs that provide financial incentives to customer owners of emergency DG units to make them available to electric system operators during peak demand periods, and at other times of system need. In addition, several regions have employed demand response (DR) programs, where financial incentives and/or price signals are provided to customers to reduce their electricity consumption during peak periods. Some customers who participate in these programs use DG to maintain near-normal operations while they reduce their use of grid-connected power.[3]
- In addition to the potential benefits for electric system planning and operations, DG can also be used to decrease the vulnerability of the electric system to threats from terrorist attacks, and other forms of potentially catastrophic disruptions, and to increase the resiliency of other critical infrastructure sectors as defined in the National Infrastructure Protection Plan (NIPP) issued by the Department of Homeland Security, such as telecommunications, chemicals, agriculture and food, and government facilities. There are many examples of customers who own and operate facilities in these sectors who are using DG to maintain operations when the grid is down during weather-related outages and regional blackouts.
- Under certain circumstances, and depending on the assumptions, DG can also have beneficial effects on land use and needs for rights-of-way for electric transmission and distribution.
- Regulation by the states of electric rates, environmental siting and permitting, and grid interconnection for DG play an important role in determining the financial attractiveness of DG projects. These rules and regulations vary by state and utility service territory, which in itself can

[3] U.S. Department of Energy, *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them: A Report to the U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005,* February 2006

be an impediment for DG developers who cannot use the same approach across the country, thus raising DG project costs beyond what they might otherwise be. In addition, utilities, often with the concurrence of regulators, have rules and charges that result in rate-related impediments that discourage DG. Recently, there have been actions to address some of these impediments, such as the work of the Institute of Electrical and Electronic Engineers (IEEE) to implement uniform DG interconnection standards. In addition, *Subtitle E – Amendments to PURPA of the Energy Policy Act of 2005,* contains provisions for state public utility commissions to consider adopting time-based electricity rates, net metering, smart metering, uniform interconnection standards, and demand response programs, all of which help address some of the rate-related impediments to DG.

- A key for using DG as a resource option for electric utilities is the successful integration of DG with system planning and operations. Often this depends on whether or not grid operators can affect or control the operation of the DG units during times of system need. In certain circumstances, DG can pose potentially negative consequences to electric system operations, particularly when units are not dispatchable, or when local utilities are not aware of DG operating schedules, or when the lack of proper interconnection equipment causes potential safety hazards. These instances depend on local system conditions and needs and must be properly assessed by a full review of all operational data.

Conclusions

Distributed generation will continue to be an effective energy solution under certain conditions and for certain types of customers, particularly those with needs for emergency power, uninterruptible power, and combined heat and power. However, for the many benefits of DG to be realized by electric system planners and operators, electric utilities will have to use more of it.

There are several potential "paths forward" for achieving this outcome. Among them are the following:

- State and regional electric resource planning processes, models, and tools could be modified to include DG as potential resource options, and thus provide a mechanism for identifying opportunities for DG to play a greater role in the electric system.
- Accomplishing this will require development of better data on the operating characteristics, costs, and the full range of benefits of various DG systems, so that they are comparable – on an equal and consistent basis – with central generation and other conventional electric resource options.
- This task is complicated somewhat because calculating DG benefits requires a complete dataset of the operational characteristics for a specific site, rendering the possibility of a single, comprehensive analysis tool, model, or methodology to estimate national or regional benefits highly improbable.
- Efforts by the States to implement the requirements posed by *Subtitle E – Amendments to PURPA of the Energy Policy Act of 2005* will likely affect the consideration of DG by the electric power industry, particularly those provisions that promote smart metering, time-based rates, DG interconnection, demand response, net metering, and fossil fuel generation efficiency.

Contents

000354

Figures

Tables

000355

Acronyms and Abbreviations

A/C	air conditioning
AC	alternating current
AEP	American Electric Power
ANSI	American National Standards Institute
CAISO	California Independent System Operator
CBM	capacity benefit margins
CDPUC	Connecticut Department of Public Utility Control
CEC	California Energy Commission
CHP	combined heat and power
CIP	critical infrastructure protection
CIR	critical infrastructure resilience
COS	cost of service
CPUC	California Public Utilities Commission
CTC	competitive transition charge
DE	Distributed Energy
DER	distributed energy resource
DFIG	doubly fed induction generator
DG	distributed generation
DHS	Department of Homeland Security
DOE	United States Department of Energy
EE	energy efficiency
EIA	Energy Information Administration
EOC	emergency operations center
ERCOT	Electric Reliability Council of Texas
EPACT	Energy Policy Act
EPRI	Electric Power Research Institute
EUE	estimated unserved energy
FERC	Federal Energy Regulatory Commission
FMCC	federally mandated congestion charges
GW	gigawatt
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utilities
IREC	Interstate Renewable Energy Council
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
IT	information technology
LDC	local distribution

LMP	locational marginal price
LNG	liquefied natural gas
LOLP	loss-of-load probability
LSE	load serving entities
MBMC	Mississippi Baptist Medical Center
MISO	Midwest Independent Transmission System Owner
MLC	multilevel converter
MNPUC	Minnesota Public Utility Commission
MVA	megavolt-amperes
NARUC	National Association of Regulatory Commissioners
NAS	National Academy of Sciences
NIMBY	not in my backyard
NIPP	National Infrastructure Protection Plan
NITS	Network Integrated Transmission Service
NJBPU	New Jersey Board of Public Utilities
NJNG	New Jersey Natural Gas Company
NRC	National Research Council
NRECA	National Rural Electric Cooperative Association
NYISO	New York Independent System Operator
NYPSC	New York Public Service Commission
OOME	out-of-merit-energy
O&M	operations and maintenance
PCC	point of common coupling
PPA	power purchase agreements
PBR	performance-based regulation
PEM	proton exchange membrane
PGE	Portland General Electric
PIER	Public Interest Energy Group
PJM	Pennsylvania/New Jersey/Maryland Interconnection (RTO)
POD	point of distribution
POU	publicly owned utilities
PSTN	Public Switched Telephone Network
PURPA	Public Utility Regulatory Policies Act
QF	qualifying facility
RE	renewable energy
ROR	rate of return
ROW	right-of-way
RTO	Regional Transmission Organization
SCE	Southern California Edison
SGIA	Small Generator Interconnection Agreement
SGIP	Small Generator Interconnection Procedures

SPP	small power production
SSP	Sector-Specific Plan
SVP	Silicon Valley Power
T&D	transmission and distribution
THD	total harmonic distortion
TMSR	Ten Minute Spinning Reserve
TRM	transmission reliability margins
TSO	transmission system operator
UL	Underwriters Laboratories
VAR	volt-ampere reactive
VOS	value of service

Definitions and Terms

alternative fuels: Fuels produced from waste products or biomass that are used instead of fossil fuels. Alternative fuels can be in gas, liquid, or solid form.

ancillary services: Necessary services that must be provided in the generation and delivery of electricity. As defined by the Federal Energy Regulatory Commission, they include: coordination and scheduling services (load following, energy imbalance service, control of transmission congestion); automatic generation control (load frequency control and the economic dispatch of plants); contractual agreements (loss compensation service); and support of system integrity and security (reactive power, or spinning and operating reserves).

ASIDI: Average System Interruption Duration, reliability measure that includes the magnitude of the load unserved during an outage. Expressed mathematically as:

$$\text{ASIDI} = \frac{\sum \text{kVA}_{\text{sustained}} \text{D}_{\text{sustained}}}{\text{N}_{\text{served}}}$$

ASIFI: Average System Interruption Frequency, reliability measure that includes the magnitude of the load unserved during an outage. Expressed mathematically as:

$$\text{ASIFI} = \frac{\sum \text{kVA}_{\text{sustained}}}{\text{kVA}_{\text{served}}}$$

availability: Used to describe reliability. It refers to the number of hours the resource is available to provide service divided by the total hours in the year.

avoided cost: See marginal cost. The avoided cost is a form of marginal cost that is required to be paid to certain qualifying facilities under the Federal Energy Regulatory Commission's regulations for qualifying facilities (18 C.F.R. Part 292).

backup power: Power provided to a customer when that customer's normal source of power is not available.

base load: The minimum amount of electric power delivered or required over a given period of time at a steady rate, or the portion of the electricity demand that is continuous and does not vary over a 24-hour period.

base load capacity: The generating equipment normally operated to serve loads on a 24-hour basis.

base load plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously and therefore has a very high capacity factor. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs, i.e., these units have the lowest variable costs in the system.

black-start capability: The ability to go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system.

bundled utility service: All generation, transmission, and distribution services provided by one entity for a single charge. This would include ancillary services and retail services.

CAIDI: The customer average interruption duration frequency index. See power reliability for more information.

$$CAIDI = \frac{SAIDI}{SAIFI} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer interruptions}}$$

capacitor: A device that maintains or increases voltage in power lines and improves efficiency of the system by compensating for inductive losses.

capacity: The rated continuous load-carrying ability, expressed in megawatts or megavolt-amperes of generation, transmission, or other electrical equipment. Other types of capacity are defined below.

> **base load capacity**: Capacity used to serve an essentially constant level of customer demand. Baseload generating units typically operate whenever they are available, and they generally have a capacity factor that is above 60%.
>
> **peaking capacity**: Capacity used to serve peak demand. Peaking generating units operate a limited number of hours per year, and their capacity factor is normally less than 20%.
>
> **net capacity**: The maximum capacity (or effective rating), modified for ambient limitations, that a generating unit, power plant, or electric system can sustain over a specified period, less the capacity used to supply the demand of station service or auxiliary needs.
>
> **intermediate capacity**: Capacity intended to operate fewer hours per year than baseload capacity but more than peaking capacity. Typically, such generating units have a capacity factor of 20% to 60%.
>
> **firm capacity**: Capacity that is as firm as the seller's native load unless modified by contract. Associated energy may or may not be taken at option of purchaser. Supporting reserve is carried by the seller.

capacity benefit margin: The amount of transmission capability that is reserved by load-serving entities to ensure access to generation from interconnected systems to meet generation reliability requirements.

capacity factor: The amount of energy that an asset transmits (e.g., for a wire) or produces (e.g., for a power plant) as a fraction of the amount of energy that could have been processed if the asset were operated at its rated capacity for the entire year.

cascading outage: The uncontrolled, successive loss of system elements triggered by an incident at any location. Cascading results in widespread service interruption that cannot be restrained.

central power: The generation of electricity in large power plants with distribution through a network of transmission lines (grid) for sale to a number of users. Opposite of distributed power.

circuit: A conductor or system of conductors through which an electric current is intended to flow.

CMI: Customer minutes of interruption, used as a measure of reliability.

CMO: Customer minutes of outage, used as a measure of reliability.

cogeneration: A process that sequentially produces electricity and serves a thermal load.

cogenerator: A generating facility that produces electricity and another form of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes. To receive status as a qualifying facility under the Public Utility Regulatory Policies Act of 1978, the facility must produce electric energy and "another form of useful thermal energy through the sequential use of energy," and meet certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission. (Code of Federal Regulations, Title 18, Part 292.)

combined heat and power (CHP): Any system that simultaneously or sequentially generates electric energy and utilizes the thermal energy that is normally wasted. Most CHP systems are configured to generate electricity, recapture the waste heat, and use that heat for space heating, water heating, industrial steam loads, air conditioning, humidity control, water cooling, product drying, or for nearly any other thermal energy need. This configuration is also known as cogeneration. Alternately, another CHP configuration may use excess heat from industrial processes and turn it into electricity for the facility.

congestion: The condition that exists when market participants seek to dispatch in a pattern which would result in power flows that cannot be physically accommodated by the system. Although the system will not normally be operated in an overloaded condition, it may be described as congested based on requested/desired schedules. Congestion can be relieved by increasing generation or by reducing load.

contingency reserve: System capacity held in reserve adequate to cover the unexpected failure or outage of a system component, such as a generator or transmission line.

cooperative electric utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

demand: The rate at which energy is used by the customer, or the rate at which energy is flowing through a particular system element, usually expressed in kilowatts or megawatts. (Energy is the rate of power used. Energy is expressed in kilowatt hours or megawatt hours; power is expressed in kilowatts or megawatts.) The demand may be quoted on an instantaneous basis or may be averaged over a designated period of time. Demand should not be confused with load. Types of demand are defined below.

instantaneous demand: The rate of energy delivered at a given instant.

average demand: The electric energy delivered over any interval of time as determined by dividing the total energy by the units of time in the interval.

integrated demand: The average of the instantaneous demands over the demand interval.

demand interval: The time period during which electric energy is measured, usually in 15-, 30-, or 60-minute increments.

peak demand: The highest electric requirement occurring in a given period (e.g., an hour, a day, month, season, or year). For an electric system, it is equal to the sum of the metered net outputs of all generators within a system and the metered line flows into the system, less the metered line flows out of the system.

coincident demand: The sum of two or more demands that occur in the same demand interval.

non-coincident demand: The sum of two or more demands that occur in different demand intervals.

contract demand: The amount of capacity that a supplier agrees to make available for delivery to a particular entity and which the entity agrees to purchase.

firm demand: That portion of the contract demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.

billing demand: The demand upon which customer billing is based as specified in a rate schedule or contract. It may be based on the contract year, a contract minimum, or a previous maximum and, therefore, does not necessarily coincide with the actual measured demand of the billing period.

demand factor: For an electrical system or feeder circuit, this is a ratio of the amount of connected load (in kVA or amperes) that will be operating at the same time to the total amount of connected load on the circuit. This is sometimes called the load diversity.

demand-side management: The term for all activities or programs undertaken by load-serving entity or its customers to influence the amount or timing of electricity they use.

district energy: Systems that are installed, owned, and operated by third parties, utility companies, or customers. These systems are often used in municipal areas or on college campuses. They provide electricity and thermal energy (heat/hot water) to groups of closely located buildings.

distributed generation: Electric generation that feeds into the distribution grid, rather than the bulk transmission grid, whether on the utility side of the meter, or on the customer side.

distributed power: Generic term for any power supply located near the point where the power is used. Opposite of central power.

distributed systems: Systems that are installed at or near the location where the electricity is used, as opposed to central systems that supply electricity to grids.

distribution system: The portion of an electric system that is dedicated to delivering electric energy to an end user. The distribution system starts inside a substation at the *distribution bus,* an array of switches used to route power out of the substation. Three-phase power flows from the bus into the *distribution feeder circuits*. The voltage on these circuits varies depending upon the length of the circuit, but is generally less than 69 kilovolts. Distribution transformers are located very near the customer and connect the distribution feeder to the *primary circuit,* which ultimately serves the customer. A distribution transformer, which may serve several residences or a single commercial facility, reduces the voltage of the primary circuit to the voltage required by the customer. This voltage varies but is usually 120/240 volts single phase for residential customers and 480/277 or 208/120 three phase for commercial or light industry customers.

diversity factor: The ratio of the sum of the coincident maximum demands of two or more loads to their non-coincident maximum demand for the same period

economic dispatch: The allocation of demand to individual on-line generating units resulting in the most economical production of electricity. (See marginal cost.)

electric service provider: An entity that provides electric service to a retail or end-use customer.

electric system losses: Total electric energy losses in the electric system. The losses consist of transmission, transformation, and distribution losses between supply sources and delivery points. Electric energy is lost primarily due to transmission and distribution elements being heated by the flow of current.

electric utility: A corporation, person, agency, authority, or other legal entity or instrumentality that owns and/or operates facilities within the United States, its territories, or Puerto Rico for the generation, transmission, distribution, or sale of electric energy primarily for use by the public and files forms listed in the Code of Federal Regulations, Title 18, Part 141. Facilities that qualify as cogenerators or small power producers under the Public Utility Regulatory Policies Act are not considered electric utilities.

emergency power units are installed, owned, and operated by customers themselves in the event of emergency power loss or outages. These units are normally diesel generation units that operate for a small number of hours per year, and have access to fuel supplies that are meant to last hours, not days.

Federal Energy Regulatory Commission: A quasi-independent regulatory agency within the U.S. Department of Energy having jurisdiction over interstate electricity sales, wholesale electric rates, hydroelectric licensing, natural gas pricing, oil pipeline rates, and gas pipeline certification.

Federal Power Act, 16 USC 791: Enacted in 1920, and amended in 1935, the act consists of three parts. Part I incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Regulatory Policies Act. These parts extended the act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

grid: Layout of the electrical transmission system; a network of transmission lines and the associated substations and other equipment required to move power.

ground fault circuit interrupter: Functions to de-energize a circuit or portion thereof within an established period of time when a current to ground exceeds some predetermined value that is less than required to operate the overcurrent protection device of the supply circuit.

interconnection: The system that connects a distributed generation resource to the grid. (Interconnection also refers to how central power plants connect to the grid.) The components of the interconnection vary according to the distributed generation system characteristics, whether the local grid is networked or radial, and the local utility requirements.

inverters: Devices that convert direct current electricity into alternating current electricity (single or multiphase), either for stand-alone systems (not connected to the grid) or for utility-interactive systems.

investor-owned utility: A class of utility whose stock is publicly traded and which is organized as a tax-paying business, usually financed by the sale of securities in the capital market. It is regulated and authorized to achieve an allowed rate of return.

land-use effects: Pertinent land-use issues include transmission line siting, power plant emissions, cooling water supply, and disposition.

line losses: Energy loss due to resistive heating in transmission lines, and to a lesser extent, in distribution feeder circuits. The energy loss is proportional to the square of the total current flow, which is in turn determined by both the real and reactive power flowing on the line. Line losses are also proportional to the resistance of the wire, which increases as the wire gets hotter.

load: An end-use device or customer that receives power from the electric system. Load should not be confused with demand, which is the measure of power that a load receives or requires. See demand.

load duration curve: A non-chronological, graphical summary of demand levels with corresponding time durations using a curve, which plots demand magnitude (power) on one axis and percent of time that the magnitude occurs on the other axis.

load factor: A measure of the degree of uniformity of demand over a period of time, usually one year, equivalent to the ratio of average demand to peak demand expressed as a percentage. It is calculated by dividing the total energy provided by a system during the period by the product of the peak demand during the period and the number of hours in the period.

load following: An energy-based ancillary service that is provided via a linear change in schedule through a period (typically one hour).

locational marginal pricing: Under locational marginal pricing, the price of energy at any location in a network is equal to the marginal cost of supplying an increment of load at that location.

loss-of-load probability: The probability that generation will be insufficient to meet demand at some point over a specific period of time.

marginal cost: The cost of producing the last increment of power needed to serve the load, usually equal to the variable cost of the last power plant added to the grid.

Momentary Average Interruption Frequency Index (MAIFI): Indicates the average frequency of momentary interruptions. Mathematically expressed as:

$$MAIFI = \frac{\sum \text{Total number of customer momentary interruptions}}{\text{Total number of customers served}}$$

network: A system of transmission or distribution lines cross-connected to permit multiple supplies to enter the system. Opposite of a radial system. Note that local interconnections are more complicated and costly for networked systems.

non-spinning reserve: 1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.

non-utility power producer: A corporation, person, agency, authority, or other legal entity or instrumentality that owns electric generating capacity and is not an electric utility. Non-utility power producers include qualifying cogenerators, qualifying small power producers, and other non-utility generators (including independent power producers) without a designated franchised service area, and which do not file forms listed in the Code of Federal Regulations, Title 18, Part 141.

off- and on-peak periods: Time periods defined in rate schedules that usually correspond to lower and higher, respectively, levels of demand on the system

on-site distributed generation includes photovoltaic solar arrays, micro-turbines, and fuel cells, as well as combined heat and power, which are installed on site, and owned and operated by customers themselves to reduce energy costs, boost on-site power reliability and improve power quality.

operating reserve: That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.

peak load, peak demand: The maximum load, or usage, of electrical power occurring in a given period of time, typically a day.

peak load distributed generation is normally installed, owned, and operated by utilities, located at a substation, or in close proximity to load centers and are used to meet period of high demand. These units are most often natural gas-fired engines, combustion turbines, or steam turbines.

peak power: Power generated by a utility unit that operates at a very low capacity factor; generally used to meet short-lived and variable high-demand periods.

power conditioning equipment: Electrical equipment, or power electronics, used to convert power into a form suitable for subsequent use. A collective term for inverter, converter, battery charge regulator, and blocking diode.

power factor: See real power, reactive power.

power quality: The *IEEE Standard Dictionary of Electrical and Electronic Terms* defines power quality as "the concept of powering and grounding sensitive electronic equipment in a manner that is suitable to the operation of that equipment." Power quality may also be defined as "the measure, analysis, and improvement of bus voltage, usually a load bus voltage, to maintain that voltage to be a sinusoid at rated voltage and frequency."

power reliability: "Power reliability can be defined as the degree to which the performance of the elements in a bulk system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply. The three most common indices for measuring reliability are referred to as SAIFI, SAIDI, and CAIDI." Realize that SAIFI and SAIDI are weighted performance indices. They stress the performance of the worst-performing circuits and the performance during storms. SAIFI and SAIDI are not necessarily good indicators of the typical performance that customers have. And, they ignore many short-duration events such as voltage sags that disrupt many customers.

primary circuits: These are the distribution circuits that carry power from substations to local load areas. They are also called express feeders or distribution main feeders.

qualifying facility: A cogeneration or small power production facility that meets certain ownership, operating, and efficiency criteria established by the Federal Energy Regulatory Commission pursuant to the Public Utility Regulatory Policies Act.

radial: An electric transmission or distribution system that is not networked and does not provide sources of power, that is, a system designed for power to flow in one-direction only. Opposite of a networked system.

rated voltage: The maximum or minimum voltage at which an electric component can operate for extended periods without undue degradation or safety hazard. Note that many components, including transformers and transmission lines can operate above or below their rated voltage for limited periods of time.

real power, reactive power: Both determined by voltage and current and are present in any electric line. The real power is available to do work (e.g., run motors and power lights) and the reactive power is needed to support the voltage on that line at the desired level. The power factor is the portion of the total power that is available to do useful work. The total power is also called the apparent power

Both voltage and current travel in the form of sine waves. These two waveforms travel over the same line but are never in perfect sync with each other. If they were in synch that would mean there would be no reactive power, and complex power would equal real power. The angle between these two waveforms, or the degree to which they are out of sync, is important in determining how much of the total power is real and how much is reactive. A series of equations are helpful in understanding the relationship between real, reactive, and total power, and in defining the power factor.

$$\text{Real Power} = (\text{Voltage}) \times (\text{Current}) \times \cos(\text{angle})$$

$$\text{Reactive Power} = (\text{Voltage}) \times (\text{Current}) \times \sin(\text{angle})$$

$$\text{Total Power} = \sqrt{(\text{Real Power})^2 + (\text{Reactive Power})^2}$$

$$\text{Power Factor} = \frac{\text{Real Power}}{\text{Total Power}} = \cos(\text{angle})$$

Inductive loads, such as motors, tend to reduce the voltage on a line so that reactive power is needed to sustain the voltage. Reactive power is also needed to overcome the voltage drop that would otherwise occur when power is transmitted over long distances. Generators can provide reactive power and capacitors and other transmission elements, such as FACTs devices, are often used to provide reactive power near the load.

regulating reserve: capacity controlled by an automatic control system, which is sufficient to maintain the voltage within the acceptable limits.

reliability: Electric system reliability has two components–adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services. Also see power reliability.

reserve capacity: The amount of generating capacity a central power system must maintain to meet peak loads.

SAIDI: The system average interruption duration frequency index. SAIDI measures the total duration of interruptions. SAIDI is cited in units of hours or minutes per year. Other common names for SAIDI are CMI and CMO abbreviations for customer minutes of interruption or outage. Also see power reliability.

$$SAIDI = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer interruptions}}$$

SAIFI: The system average interruption frequency index. Typically, a utility's customers average between one and two sustained interruptions per year. See power reliability for more information.

$$SAIFI = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}}$$

small power production (SPP): Under the Public Utility Regulatory Policies Act, a small power production facility (or small power producer) generates electricity using waste, renewable (water, wind and solar), or geothermal energy as a primary energy source. Fossil fuels can be used, but renewable resource must provide at least 75% of the total energy input. (See 18 CFR 292. 2004. "Regulations Under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978 with Regard to Small Power Production and Cogeneration." *Code of Federal Regulations*, Federal Energy Regulatory Commission.)

$SARFI_x$: $SARFI_x$ represents the average number of specified rms variation measurement events that occurred over the assessment period per customer served, where the specified disturbances are those with a magnitude less than x for sags or a magnitude greater than x for swells.

spinning reserve: Unloaded generation synchronized to the system and fully available to serve load within the specified time period following an unexpected outage or load fully removable from the system within that same time period.

standby demand: The demand specified by contractual arrangement with a customer to provide power and energy to that customer as a secondary source or backup for the outage of the customer's primary source. Standby demand is intended to be used infrequently by any one customer.

substations: Equipment that switches, steps down, or regulates voltage of electricity. Also serves as a control and transfer point on a transmission system.

supervisory control: Supervisory control refers to equipment that allows for remote control of a substation's functions or a distributed generation resource from a system control center or other point of control.

synchronous condensers: A synchronous condenser is a synchronous machine running without mechanical load and supplying or absorbing reactive power to or from a power system. Also called a synchronous capacitor, synchronous compensator or rotating machinery. These can be former power generators that have been converted to only produce reactive power.

total power: See real power and reactive power.

transmission constraint: A limitation on one or more transmission elements that may be reached during normal or contingency system operations.

transmission lines: Transmit high-voltage electricity from the generation source or substation to another substation in the electric distribution system.

overhead transmission lines: Overhead alternating current transmission lines share one characteristic; they carry three-phase current. The voltages vary according to the particular grid system they belong to. Transmission voltages vary from 69 kilovolts up to 765 kilovolts.

subtransmission lines: These lines carry voltages reduced from the major transmission line system, usually 69 kilovolts.

transmission reliability margin: This is reserved transmission capacity to address unanticipated system conditions such as normal operating margin, parallel flows, load forecast uncertainty and other external system conditions. It is the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure.

transmission system (electric): An interconnected group of electric transmission lines and associated equipment for moving or transferring electric energy in bulk between points of supply and points at which it is transformed for delivery over the distribution system lines to consumers, or is delivered to other electric systems.

variable costs: Those costs needed to operate a power facility, including fuel and variable operations and maintenance. These costs do not include fixed operations and maintenance or fixed capital costs.

watt (W): The unit of electric power, or amount of work (J), done in a unit of time. One ampere of current flowing at a potential of one volt produces one watt of power.

voltage collapse: An event that occurs when an electric system does not have adequate reactive support to maintain voltage stability. Voltage collapse may result in outage of system elements and may include interruption in service to customers.

voltage control: The control of transmission voltage through adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Section 1. Introduction

Distributed generation (DG) systems are not new phenomena. Prior to the advent of alternating current and large-scale steam turbines, all energy requirements—heating, cooling, lighting, motive power—were supplied at or near their point of use. Technical advances, environmental issues, inexpensive fuel, the expanding role of electricity in American life, and its concomitant regulation as a public utility, all gradually converged around gigawatt-scale thermal power plants located far from urban centers, with high-voltage transmission and lower voltage distribution lines carrying electricity to every business, facility, and home in the country.

> **Economies of Scale #1: Central Generation**
>
> The electricity generator of choice for early utilities was the reciprocating engine. But steam turbines (circa 1884) used fewer mechanical steps, and were therefore more energy efficient, smaller, and quieter than reciprocating engine generators. More importantly, turbines could be scaled up far beyond the physical limits of reciprocating engines, and could produce more power with proportionally less investment in material. The concept of "economies of scale"—increasingly larger units producing electricity at successively lower unit costs—was also shown to apply to turbines.

As the centralized electricity system became ubiquitous, it seemed we had settled on a permanent delivery system for that portion of our energy needs. Electric utilities provided the motive force for a broad array of production-improving devices that helped drive the American industrial boom. Steam turbines leveraged America's vast, inexpensive fuels that could be burned remotely (helping remove coal-blackened skies from city centers) to produce electricity at reasonable rates within broadly acceptable levels of reliability. Both the utility businesses and the quality of their services were overseen by appointed or elected regulatory officials in every state. At the federal level, the Federal Energy Regulatory Commission (FERC), successor to the Federal Power Commission, was chartered to oversee wholesale markets and the sale of electricity over the interstate transmission network. The network itself grew out of a need to improve individual plant reliability (multiple power plants connected by transmission lines provide a higher level of service reliability than any single generator) and load factor. This complex network of generators, transmission and distribution systems provided the United States with electricity from low-cost fuels for decades.

Throughout, electric power technologies continued to advance. For example, improved materials and engineering designs for photovoltaic panels, microturbines, fuel cells, digital controls, and remote monitoring made it possible to tailor energy supplies for specific customers.

The savings realized from mass production (i.e., building ever bigger power plants) reached its peak in the 1960s, and the economic benefits of mass customization (smaller, modular systems sized for the energy required) eventually began to outpace the production cost savings of legacy technologies (Hirsh 1989). A modern example of this might be an energy customer with a substantial heating or cooling requirement, or continuous power quality needs beyond the service standard established by the state regulatory commission. In such cases, the cost of using grid-supplied electricity, additional heating and/or cooling equipment, and voltage or harmonic regulation equipment on-site may indeed be more expensive than providing those services either themselves or from a third party provider.

Economies of Scale #2: Long-Distance Transmission

The advent of alternating current (AC) transformers overcame direct current's early technical limitations, and enabled electricity to flow for tens or even hundreds of miles without significant voltage degradation. However, this network of high-voltage lines and transformers would have its own limitation, including thermal line losses and the need for reactive power.

This combination of steam turbines and alternating current created the vast complex of power plants and transmission lines that we know today–far from urban centers. The air pollution, rail congestion, and visual hallmarks of the U.S. electricity industry have been removed from most constituents' view.

Today, technology advances make it possible to relocate generators within urban centers, thus enabling the capture of benefits from improved system resiliency and improved performance of local power.

(Source: Hirsh 1989)

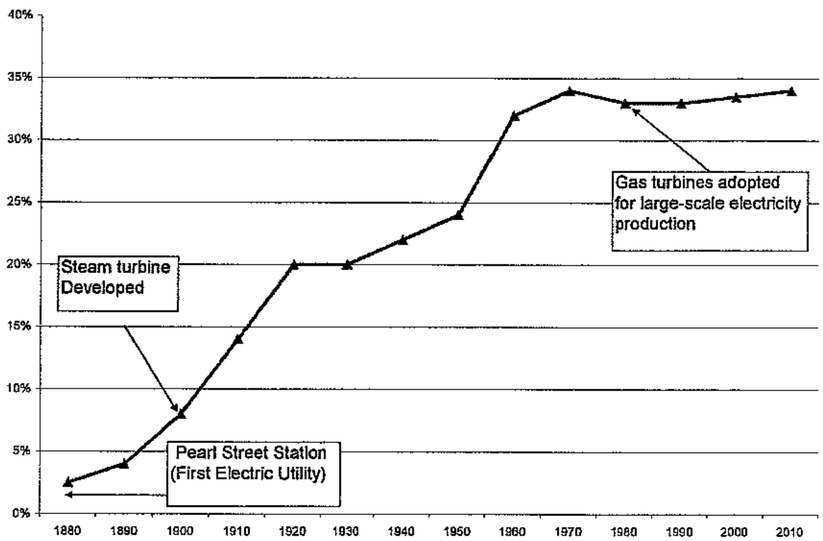
In such instances, it is often the case that DG is a financially attractive option, and that it can be installed and operated safely, and in concert, with the grid, thus producing benefits both for the consumer and the electric power system overall. (Kingston et al. 2005).

1.1 Limits to Central Power Plant Efficiencies

From 1900 to 1960, utilities continuously increased the thermal efficiency in steam turbines, and squeezed more kilowatt-hours from each unit of fossil fuel. In the 1950s, manufacturers could theoretically achieve 40% thermal efficiency. But at this level, problems began to become apparent (see Figure 1.1).

When super-heated pressurized steam pressed against the turbine blades and boiler tubes, metallurgical fatigue increased substantially, decreasing the reliability of huge power plants (and increasing maintenance costs). Plant managers realized that operating at lower efficiencies (and lower temperatures) might be more economical. While making economic sense, though, the decision to stop pushing thermal efficiencies meant that utilities could no longer expect to see significant cost declines from this aspect of their industry's technological progress. .

Figure 1-1. Average U.S. Fossil Power Plant (Fleet) Efficiencies, 1900-2000



Source: Energy Information Administration 2004.

1.2 Changing Energy Requirements Affect Transmission and Distribution Economics

As steam turbine systems began to realize thermal efficiency limits, the composition of electricity demand in the United States began to shift. Centralized air conditioning, virtually non-existent in homes built before the 1960s, began to enter the residential market. By 2000, most new homes built in America included central air conditioning (Cooper 1998).

- In 1978, 23% of U.S. housing units had central air conditioning; by 1997, the share had more than doubled, to 47%.
- By 1997, 93% of the housing units in the South had some type of air conditioning (Hoge 2006).

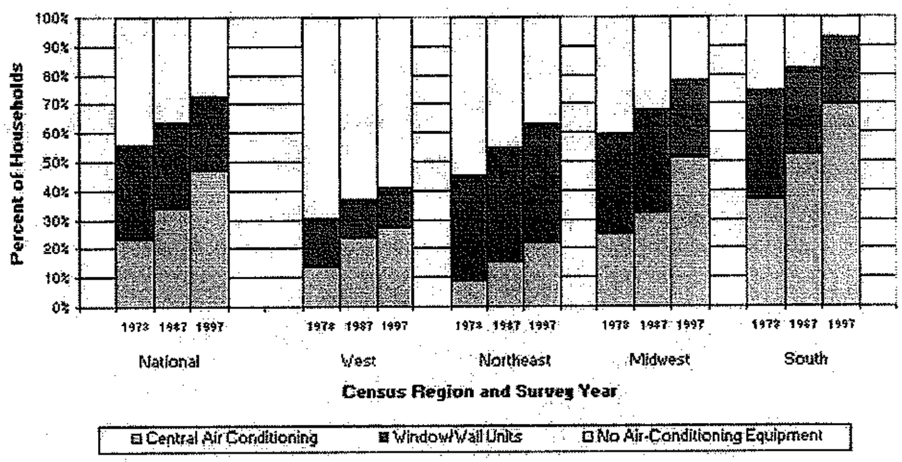
Air conditioning made possible the dramatic migration of Americans to the western and southwestern United States. But it also changed the nature of electricity demand. Central air conditioning systems generally require 1 kW of capacity when operating, for every ton of cooling[1]. Historically, air conditioners have been sized to provide a ton of cooling capacity for every 500 square feet of home interior. Some state energy efficiency regulations have abolished this arbitrary figure (i.e., California's Title 24), but in many parts of the country contractors still adhere to this earlier assumption, accelerating peak electricity demand growth without any specific correlation to personal comfort.

The expansion of central air conditioning accelerated electricity demand growth in residential markets, but that demand occurs in "needle peaks" of short duration on the grid. This in turn forced utilities to

[1] Although new federal standards mandate an efficiency of 13 SEER or better for central air conditioners, virtually all residential a/c units installed to-date are 10 SEER, which, when improperly sized for the building, require up to twice as much energy per unit of cooling. For more information comparing air conditioner demand by size, appliance age and SEER rating, see http://www.fsec.ucf.edu/bldg/pubs/effhvac/index.htm.

expand electricity distribution capacity to power air conditioning systems during hot afternoons, but that expanded capacity came with a very poor "load factor,"– there were very few hours each day in which those kilowatt-hours of electricity were being purchased, to pay for the additional wire, transformer, and substation capacity (Figure 1.2).

Figure 1-2. U.S. Market Penetration of Air Conditioning Equipment, 1978-1997



Sources: Energy Information Administration; 1978, 1987, and 1997 Residential Energy Consumption Surveys.

Source: Energy Information Administration 2000.

1.3 Electricity Consumption versus Peak Load Growth Trends

1.3.1 National

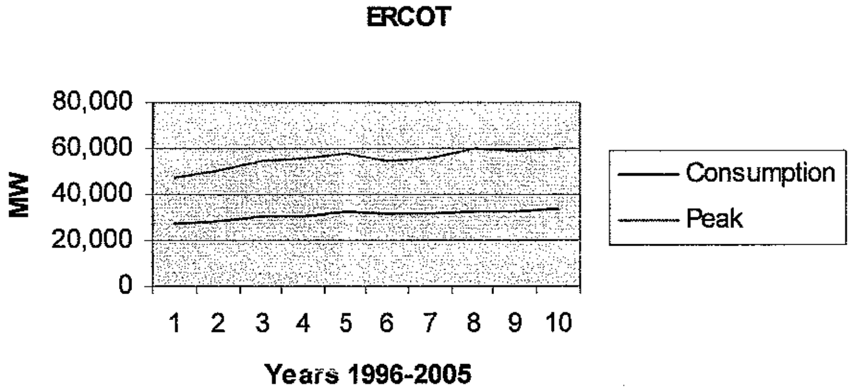
According to U.S. Department of Energy, Energy Information Administration data from the year 2000 onwards, peak load for the contiguous United States is growing slightly faster relative to the net generation needed to meet base loads in both the electric power sector (alone) and the net generation from the electric, commercial, and industrial sectors (combined total) on the tail end of the trend. Yet patterns of growth deviation are not visibly significant at this level.

1.3.2 Regional

The North American Electric Reliability Council (NERC) consists of Regional Reliability Councils representing NERC regions across the country. By charting peak demand vs. electricity consumption[2] in one region, the Electric Reliability Council of Texas, Inc. (ERCOT), it can be seen that the two factors track in a fairly proportional manner, with peak demand growing slightly faster than aggregate (Figure 1.3).

2 Electricity consumption converted to MW by dividing GWh's by 8766 hours/year and by a factor of 1,000

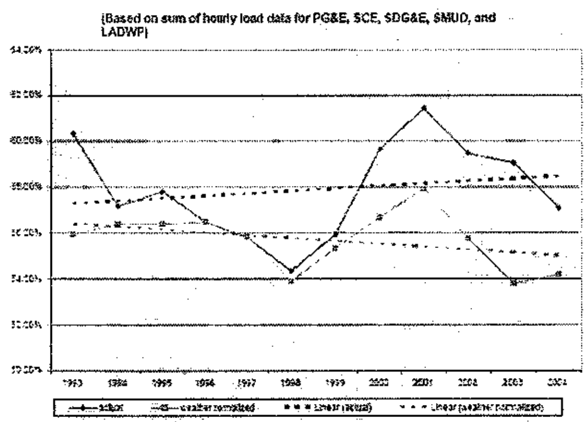
Figure 1-3. Aggregate Versus Peak Electricity Demand in ERCOT, 1996-2005.



1.3.3 State

As noted above, the measure of the "peakiness" of the electric system is load factor, which is calculated by dividing average annual hourly consumption by annual peak consumption. If peak demand grows faster than annual average consumption, the load factor decreases. Figure 1.4 shows that California's weather-adjusted load factors have dropped 2.535% (from 56.41% in 1993 to 54.98% in 2004) over the 11-year period from 1993-2004 as air conditioner loads have increased (Gorin 2005).

Figure 1-4. Statewide Annual Load Factor, Actual and Weather-Adjusted, 1993-2004

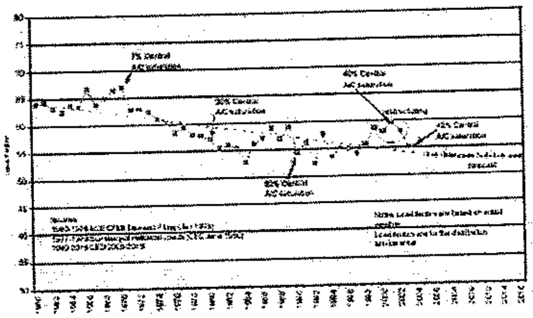


Source: Gorin 2005

The trends are not uniform across utility service areas. Declining load factors are evident for Pacific, Gas and Electric Company (PG&E) and Southern California Edison (SCE). SCE's service area load factor has declined more than PG&E's over the past 34 years. SCE's load factor is currently near 55, while PG&E is just below 60 (as shown in Figures 1.5 and 1.6, below).

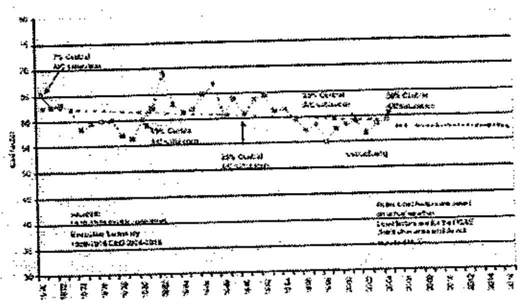
Various reasons could explain the declining load factors and the varying rates of decline. In the 1970s and early 1980s, the spread of central air conditioning in both hotter and coastal areas increased peak summer usage as more floor space was cooled. This trend tended to lower the load factor for both PG&E

Figure 1-5. SCE Historic Load Factors 1960-2004



Source: Gorin 2005

Figure 1-6. PG&E Historic Load Factors 1970-2004



Source: Gorin 2005

and SCE. Demand analysts hypothesized that as more houses were built inland, as house size increased, and as electricity bills declined as a percent of total income, more air conditioning would be used, and the residential load factor would decline. To document how central air conditioning has affected load factors, the service area charts include equipment saturation. In PG&E's service area, only 7% of homes had central air conditioning in 1970 compared to 26% in 1990 and 30% in 2004. During that period, load factors dropped from 63 in 1970 to 60 in 1990.

1.4 The Era of Customized Energy

Until recently, every electric motor, windup clock, and light bulb was virtually insensate to minor voltage fluctuations. Most people recall the occasional "brown out" from earlier eras, when the lights would flicker or dim momentarily as the electricity grid rode through a brief voltage anomaly. But the introduction of integrated circuits into everything from washing machines and televisions to alarm clocks has dramatically reduced the ability of most loads—equipment or processes requiring electricity—to ride through voltage anomalies without disruption. DG, particularly when it employs battery energy storage or capacitors, provides site-specific electricity management options for load-sensitive customers.

Distributed generation systems also enable customers to design their energy supply to be more closely aligned with their physical needs. For example, space heating and cooling often requires thermal as well as electric energy. By employing a combined heat and power (CHP) system on-site, commercial or industrial customers can capture the waste heat and use it for local thermal needs.

1.5 Distributed Generation Defined

Solar panels installed on homes are distributed generation. An emergency generator sitting behind a convenience store is DG. A farmer using the waste from his own animals to generate electricity is DG. A hospital using a gas turbine for electricity and recycling the waste heat to wash bedding or provide hot showers, is DG.

The EPACT 2005, Section 1817, terms "cogeneration" or "small power production" appear to be used to describe types of this broader industry term "distributed generation," which applies to energy systems that produce electricity and/or thermal energy at or near the point of use. Because such installations are typically situated within or near homes, buildings or industrial plants, the terms "distributed generation," "cogeneration" and "small power production" are interchangeable. This study will encompass all forms of DG technologies, ranging from those that produce only electricity (photovoltaic systems and wind turbines) to those that produce a combination of heat and power—with engines or turbines—installed at or near the point of use. The basis for this assumption is the EPACT section title, which uses the term "Distributed Generation (71 FR 4904- 4905)."

The enhanced efficiencies gleaned from the "free" fuels of solar or wind energy, and the recycled energy of CHP, are central to the DG proposition. Among central thermal power plants, as explained earlier, maximum efficiency is limited by metallurgical considerations, which limit the maximum temperature within the system, and by the need to reject heat to the environment. However, in a CHP system, much of that rejected heat is put to useful work, so the overall efficiency can be greater than 75%. Considering the fuel that would have otherwise been consumed to provide that thermal service by some other means (i.e., water heating or electric air conditioning), the net cost of electricity service from a CHP system is much reduced.[3]

- *On-site DG* includes photovoltaic solar arrays, micro-turbines, and fuel cells, as well as CHP, which are installed on-site, and owned and operated by customers themselves to reduce energy costs, boost on-site power reliability, and improve power quality.
- *Emergency power units* are installed, owned, and operated by customers themselves in the event of emergency power loss or outages. These units are normally diesel generation units that operate for a small number of hours per year, and have access to fuel supplies that are meant to last hours, not days.
- *District energy* systems are installed, owned, and operated by third parties, utility companies, or customers. These systems are often used in municipal areas or on college campuses. They provide electricity and thermal energy (heat/hot water) to groups of closely located buildings.

1.6 Status of Distributed Generation in the United States Today

More than 12 million DG units are installed across the United States today, with a total capacity over 200 GW. In 2003, these units generated approximately 250,000 GWh.[4] Over 99%of these units are small emergency reciprocating engine generators or photovoltaic systems, installed with inverters that do not feed electricity directly into the distribution grid[5]. However, as shown in Figure 1.7, this large number of smaller machines represents a relatively small fraction of the total installed capacity (Energy Information Administration 2005).[6]

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3 For a complete explanation of CHP system technologies and efficiencies, see Kaarsberg and Roop in Borbely, A. and J.Kreider, 2001, *Distributed Generation: The Power Paradigm for the New Millennium*, CRC Press: Boca Raton, Florida.

4 Distributed generation is defined in a Resource Dynamics Corporation (RDC) report, "Case Study for Transmission and Distribution Support Applications Using Distributed Energy Resources," as units producing power principally used on-site and smaller than 60 MW in capacity. These data have been augmented with information on photovoltaic shipments from the Energy Information Administration's "Renewable Energy Annual 2004."

5 Emergency generators are generally interconnected to the building on the customer's side of the utility meter, and do not feed the grid itself. Photovoltaic systems are installed with UL 1741-certified inverters that automatically disconnect from both the grid and the building in the event of a loss of utility service.

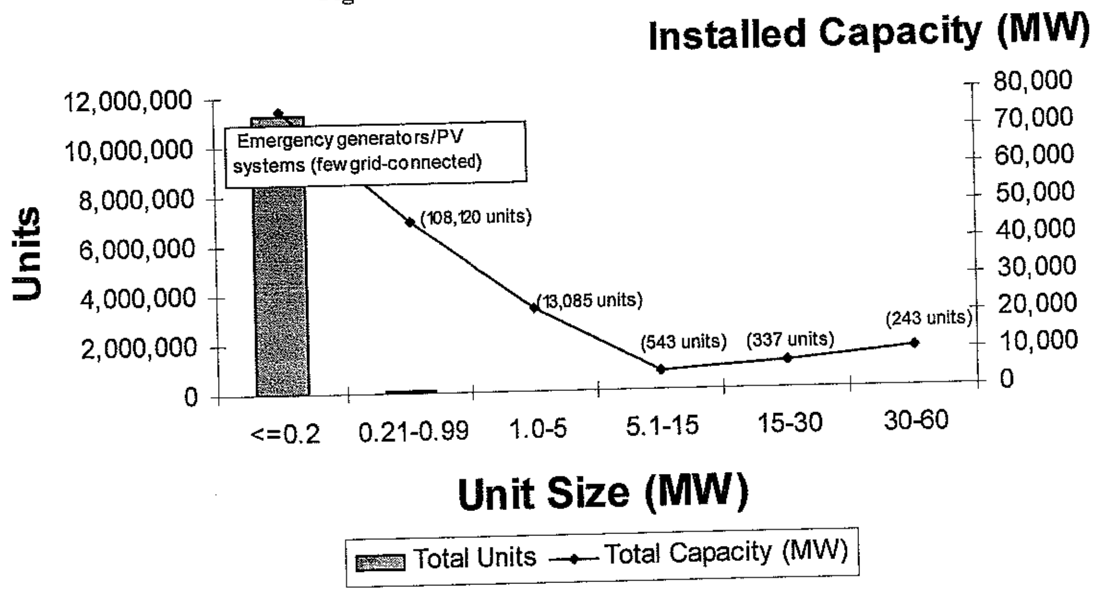
6 As of the summer of 2005, 909,100 MW of electric generating capacity were installed within the United States.

1.7 Distributed Generation Drivers: The Changing Nature of Risk

Capital markets have long understood the value of hedging financial or economic risk. For regulated electric utilities, risk has been managed through fuel adjustment clauses and rate case hearings that enabled the utility to account for changes in earlier cost projections.

But the nature of applied risk for both energy customers and utilities has changed over the past few decades, and the introduction of smaller, more modular technologies capable of operating on a wide variety of fuels—or no fuel—offers direct material benefits to both the energy customer and his/her utility service provider. For an extensive discussion of DG as a financial risk management tool, see *Small Is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size* (Lovins et al. 2002).

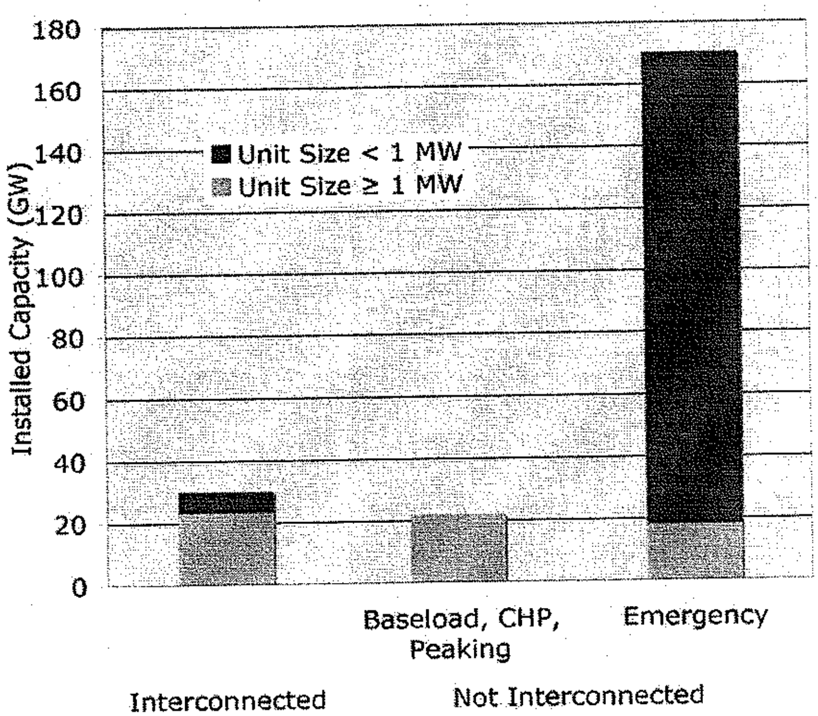
Figure 1-7. U.S. DG Installed Base (2003)[7]



Other risk-related benefits have driven growth in the DG market. As Figure 1.8 shows, the vast majority of DG units in the United States today are actually backup or emergency generators, installed to operate when grid-supplied electricity is not available. But September 11, 2001, the Northeast Blackout of August 2003, and Hurricane Katrina have all impressed upon us the growing need to maintain secure civil operations during a catastrophic event. By changing out the switchgear associated with an on-site CHP system, a hospital or other facility can use an integrated DG unit to reduce their electricity bills on a daily basis, and provide emergency power, heating and cooling during a weather-related or human-induced disruption.

7 RDC data has been augmented with information on photovoltaic panel shipments from the Energy Information Administration's "Renewable Energy Annual 2004."

Figure 1-8. U.S. Distributed Generation Capacity by Application and Interconnection Status[8]



Over the past 100 years the role of electricity has evolved. In today's Information Age, reliable electricity is no longer a luxury; it is now essential. The grid is critical to all aspects of safely operating our cities, businesses, and homes. However, the electric grid has not kept pace with surging demand. Even with substantial improvements in energy-efficient building, electricity demand has increased from 1500 billion kWh in 1970 to over 3700 billion kWh in 2004, and is projected to reach 5600 billion kWh by 2030 (see Figure 1.9). Investments in new transmission and distribution have not maintained this pace of development.

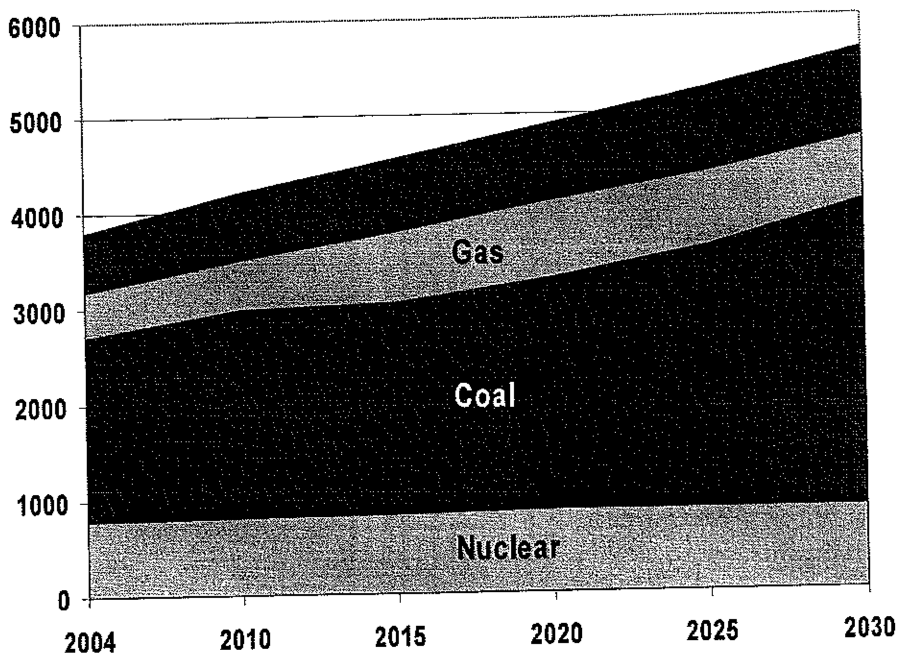
As the 12 million DG units already installed attest, DG currently plays a significant role in the nation's energy system. However, the vast majority of these units have been installed by consumers to meet needs for back-up power during outages. While some power companies offer incentives to consumers to run their back-up power units during peak load periods and other times of system need, DG today is primarily a consumer energy solution, and not one that is well integrated to meet the day-to-day planning and operational needs of the electric power system.

8 Created by ORNL using data from "Resource Dynamics Corporation, The Installed Base of U.S. Distributed Generation," *DG Monitor*, Vienna, VA, 2005

1.8 The "Cost" versus "Benefit" Challenge

The result of this lack of integration of DG in the electric system is that many of the direct, and virtually all of the indirect, benefits of DG systems are not captured within traditional utility cash-flow accounting. This is primarily the product of a historic regulatory structure that has produced specific capital investment and operational priorities, and the significant task of keeping the vast network of central generation units, power lines, and substations, up and running and reliably meeting consumer needs for electric power.

Figure 1-9. Electricity Forecast (billion kWh)[9]



Since their inception, state public utility commissions have executed their charters seriously, constantly pursuing the best possible combination of reliable service and lowest reasonable cost. This sometimes collegial, other times contentious, relationship with the electric power companies within their jurisdiction, has evolved into a series of generally accepted rules and business practices regarding the appropriate method for estimating a technology's appropriateness, usefulness, safety, and public benefit. However, because they have primarily been consumer-based solutions, DG systems—and their business models—generally have developed outside of the traditional regulatory framework.

1.8.1 Identifying Benefits versus Services

EPACT 1817 calls for an analysis of the potential for DG to provide specific benefits to the grid and to other customers within that service territory. However, some of the "benefits" enumerated in EPACT 1817 are in fact services, such as the provision of ancillary services, while others are distinct benefits that may accrue to the use of DG, as a complement to the existing centralized system. Table 1.1 provides a means for distinguishing between these two concepts. The first column lists specific services

9 Data provided by the Energy Information Administration, Electric Power Annual, 2005

DG is capable of providing. The potential benefits derived from those services can be categorized in one or more of the columns on the right-hand side of the chart. For example, new capacity investments may be deferred by reducing peak power requirements on the grid, or by the provision of ancillary services. Distributed generation available as an emergency supply of power can also be used in demand response programs to reduce congestion, or increase system reliability via peak-sharing.

Table 1.1. Matrix of Distributed Generation Benefits and Services

		Benefit Categories							
		Energy Cost Savings	Savings in T&D Losses and Congestion Costs	Deferred Generation Capacity	Deferred T&D Capacity	System Reliability Benefits	Power Quality Benefits	Land Use Effects	Reduced Vulnerability to Terrorism
DG Services	Reduction in Peak Power Requirements	✓	✓	✓	✓	✓	✓	✓	✓
	Provision of Ancillary Services –Operating Reserves – Regulation – Blackstart –Reactive Power	✓	✓	✓	✓	✓	✓	✓	✓
	Emergency Power Supply	✓	✓			✓	✓		

T&D= transmission and distribution.

Although it is not within the scope of this study to address every economic and social contribution that might accrue to a modular, distributed generation landscape, Lovins et al. (2002) have identified over 200 potential benefits that can be derived from DG. The list below is a sampling. Many of these benefits, however, such as localized manufacturing and economic development, cannot be expressed in retail electricity rates. To realize the full suite of benefits of DE systems requires a more comprehensive approach to energy as an element of economic activity, within state and local jurisdictions.

1.9 Potential Regulatory Impediments and Distributed Generation

Government regulation of electricity production is dictated by the type of interconnection a generator has with the larger transmission or distribution system. A small, home-installed photovoltaic array or diesel-fueled emergency generator supplies a building within the lower voltage distribution system, and does not have direct electrical access to the interstate transmission system. All such DG systems connected at or below the lower voltage distribution grid, are regulated by local and state authorities. The Federal Energy Regulatory Commission (FERC) oversees the interconnection and offtake contracts of generators attached to the higher voltage transmission system in two separate rulings, as noted in Section 8.

Because DG systems are most commonly connected at the lower voltage distribution system, the FERC historically has had little jurisdictional authority. However, Section 210 of the Public Utility Regulatory Policy Act of 1978 (PURPA) recognized the higher system efficiencies of load-sited cogeneration plants, compared with electricity-only steam power plants, and provided a legal framework for smaller, privately owned qualifying facilities to interconnect with the electric transmission system and sell their excess electricity production to the incumbent utility.

Sample Benefits of Distributed Generation Systems

1. Shorter construction times
2. Reduced financial risk of over- or under-building
3. Reduced project cost-of-capital over time due to better alignment of incremental demand and supply
4. Lower local impacts of smaller units may qualify for streamlined permitting or exempted permitting processes, reducing fixed costs per kW
5. Significantly reduced exposure to technology obsolescence
6. Local job creation for manufacturing, technician installers/operators
7. Higher local, small-business development and taxes vs. overseas manufacturing
8. Lower unit-cost, automated manufacturing processes shared with other mass-production enterprises (i.e., automotive industry)
9. Shorter lead times reduce risk of exposure to changes in regulatory climate
10. Significant reduction in fuel disruption risk (portfolio of locally produced fuels and "fuel-less" technologies—solar, wind)
11. Reduced fuel-forward price risk
12. Reduced trapped equity
13. Reduced exposure to interest-rate fluctuations
14. Potential for more modular, routine analysis for capital expansions
15. Multiple off ramps for discontinued projects, without same level of risk
16. Ability to redeploy portable resources as demand profiles change
17. Portability = Higher capacity utilization
18. Reduced site remediation costs after decommissioning
19. Higher system efficiency reduces ratio of fixed-to-variable costs (fuel)
20. Potential for lower unit costs for replacement parts when mass produced
21. Displaces that portion of customer load with highest line losses
22. Displaces that portion of customer load with greatest reactive power requirements
23. Displaces that portion of customer load with highest marginal energy costs
24. Weather-related (solar, wind) interruptions more easily predicted and of shorter duration than equipment failures at central plants
25. "Hot swap" capability – when one DG module (panel, tracker, inverter, turbine) is unavailable, all other modules continue operating
26. Load siting reduces or eliminates line losses on electric transmission and distribution lines
27. Inherently improved system stability due to multiplicity of inputs
28. Reduced regional consequences of system failure
29. Improved transmission and distribution reliability due to reduced peak loading, conductor and transformer cooling
30. Fast ramping within the distribution system, ability to reduce harmonic distortions at customer's site.

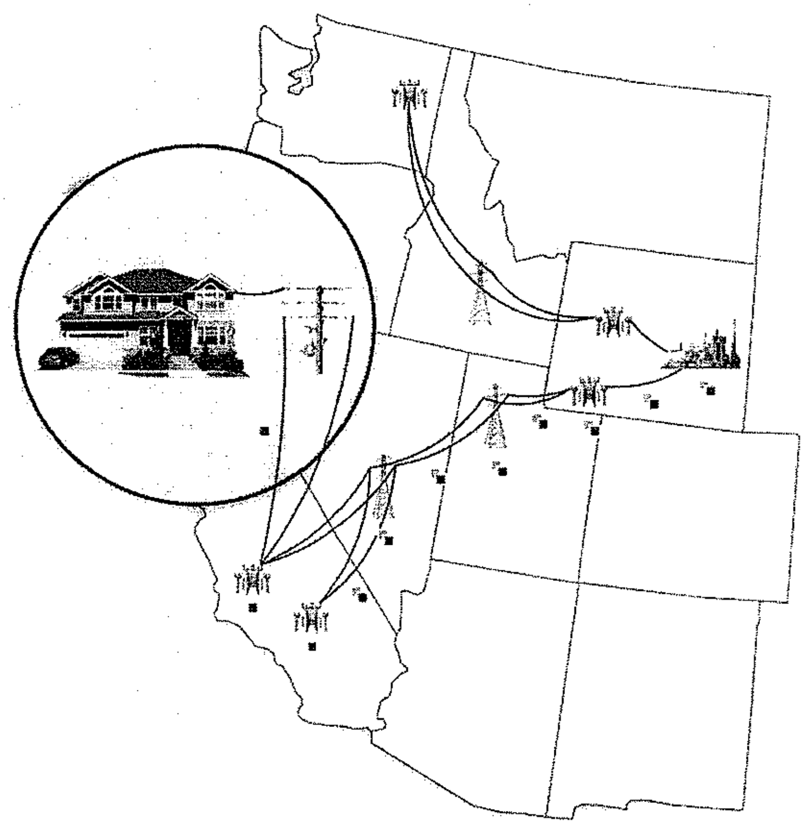
Source: Lovins, A., Datta, K. and T. Feiler, A. Lehmann, K. Rabago, J. Swisher, K. Wicker, 2002. *Small is Profitable: The Hidden Economic Benefits of Making Electrical Resources the Right Size.* Rocky Mountain Institute, Snowmass, Colorado.

The *Energy Policy Act of 2005 (EPACT 2005)* repealed the *Public Utility Holding Company Act of 1935*, eliminated PURPA restrictions on utility ownership of qualifying facilities, and established that no utility shall be obligated under PURPA to enter into a new contract with or to purchase power from a qualifying facility that is found to have nondiscriminatory access to certain types of developed markets. FERC has also issued a rulemaking on the electrical interconnection of small generators.

This mix of federal and state jurisdictions, as shown in Figure 1.10, has unintentionally inhibited the full deployment of DG across the United States. Prudence reviews for capital expenditures, retail and wholesale rates, wholesale market power, congestion management, consumer advocacy and plant siting are just a few of the issues that affect the electric utility industry as it relates to DG, with both overlaps and gaps in jurisdictional reach at the state and federal level. This confusion has negatively impacted the cost-effective use of DG in many regions.

Utility rate structures can inadvertently discourage investment in local energy sources that bypass much of the energy losses outlined in Figure 1.10. Table 1.2 provides a few examples of the impact of rate design on the simple payback of DE.

Figure 1-10. Jurisdictions of Electric Infrastructure



- **FERC** - Transmission system interconnection and off take contracts of power plants, all wholesale marketing and sales, public power entities
- **State** - power plant and transmission line siting/permitting, distribution system siting and operations, all retail market operations, investor-owned utilities

Source: Tyler Borders, PNNL.

Table 1.2. Impact of Rate Design on Distributed Generation

Impediment Description	Barrier Cost	Simple Payback Impact (yrs)
Standby Charge ($6/kW/mo)	-$72,000 annually	+1.5
Non-Coincidental Off Peak ($12.5/kW/mo)	-$127,000 annually	+3.3
Interconnect Charges	$300,000 upfront	+1.0
Load Retention Rate	-$245,000 annually	+2.4
Exit Fee	$1,000,000 upfront	+2.9

1.9.1 DG-related Provisions of the Energy Policy Act of 2005

Additional provisions in EPACT affect the development of DG and consideration of it by consumers and electric system planners and operators.. For example, EPACT Section 1211 calls for the development of an Electric Reliability Organization (ERO) and implementation of mandatory and enforceable electric reliability standards. These standards are likely to affect investment decision-making by electric power companies and their assessments of the relative merits of DG, along with other electric resource options. EPACT Section 1221 calls for DOE to study transmission congestion and possibly designate constrained areas as national interest electric transmission corridors. Areas of transmission congestion that are identified in the study could spur evaluation of resource options to reduce the congestion, including DG.

EPACT Subtitle E contains amendments to the Public Utility Regulatory Policies Act (PURPA).[10] EPACT Section 1251 calls for the adoption of standards for net metering; these can impact the interconnection of DG systems with the electric grid. EPACT Section 1252 contains standards for smart metering and time-based pricing which are generally considered to be important "enabling mechanisms" for consideration of investments in DG by consumers and electric power companies. Furthermore, EPACT Section 1252 also generally promotes demand response programs nationwide. These programs have been important mechanisms for establishing financial incentives for consumers to install DG, and to operate them in a manner that provides peak load and reliability benefits for the overall electric system[11] EPACT Section 1253 discusses conditions under which the purchase of electricity from qualifying cogeneration facilities or qualifying small power production facilities by utilities is not mandatory. EPACT Section 1254 calls for the adoption of standards for interconnection of DE systems and calls for states to consider using the Institute of Electrical and Electronic Engineers (IEEE) Standard 1547 as the basis under which the states offer interconnection services. IEEE 1547 involves a set of standards (1547.1–1547.6) that IEEE requires be reaffirmed every five years.[12]

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10 Public Utility Regulatory Policy Act of 1978

11 Energy Policy Act of 2005, Subtitle E, Section 1252. The report to Congress, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them" was published in February 2006 by the U.S. Department of Energy.

12 IEEE Standard 1547-2004. 2004. "1547 IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems." Institute of Electrical and Electronics Engineers, Piscataway, New Jersey.

Section 2. The Potential Benefits of DG on Increased Electric System Reliability

2.1 Summary and Overview

Electric system reliability is a measure of the system's ability to meet the electricity needs of customers. It is a term used by electric system planners and operators to measure aggregate system conditions, and as an aggregate measure, it generally applies to entire service territories or control regions. As such, the reliability of the electric system depends on the reliability of that system's component parts, including, for example, power plants, transmission lines, substations, and distribution feeder lines. To help ensure a reliable system, planners and operators prefer having as much redundancy in these components as can be justified economically.

System reliability is also dependent on events that affect daily operations, including the decisions made by grid operators in real-time in response to changing system conditions. Operators like to have as much real time, and location-specific information as they can get about system conditions, as well as the ability to control power flows and dispatch power plants to enable effective response when problems occur. Weather is the primary reason for reliability problems, and includes problems caused by lightening strikes, high winds, snowfall, ice, and unexpectedly hot weather. The goal of both planners and operators is to have as resilient a system as possible that can adjust to problems without causing major consequences, and that when outages do occur, they are short-lived and affect the fewest number of customers as possible.

DG has the potential to be used by electric system planners and operators to improve system reliability; and there are a few examples of this being done currently. As discussed, DG is primarily used today as a customer-side energy resource for services such as emergency power, uninterruptible power, combined heat and power, and district energy. Utilities could do more to use the DG already in place, and they could increase investment in DG resources themselves. However, successful business models for more widespread utility use of DG are limited to certain locations and certain conditions.

There are currently two primary mechanisms being used today by utilities to access customer-side DG for reliability purposes:

- Several utilities offer financial incentives to owners of emergency power units to make them available to grid operators during times of system need.
- Several regions offer financial incentives or price signals to customers to reduce demand during times of system need (e.g., demand response programs), and some participants in these programs use DG to maintain near-normal on-site operations while they reduce their demand for grid-connected power.

Madison Gas and Electric (MGE) owns and operates backup generators at several business customers' sites. These customers, who must have a monthly demand of at least 75 kW, pay a monthly fee based upon their maximum annual demand to have the generation available if power is interrupted. If the grid power fails, the backup units provide power within 30 seconds. After the grid is restored, these units automatically synchronize and then shut down so that the customer does not incur another service interruption. MGE, which takes responsibility for all environmental permits, can also use these units to boost system reliability during an electrical emergency. (Source: Madison Gas and Electric 2006)

Interest in these and other mechanisms to use DG to improve system reliability appears to be growing, as concerns mount across the country about the adequacy of current resource plans (e.g., construction of new generation, transmission, and distribution facilities) to maintain the reliability of the nation's electric system.[16] There are several reasons for these growing concerns. For example, the electric system was generally designed to provide reliable service by providing multiple generators with a total capacity greater than the anticipated system peak demand, providing overlapping transmission networks, and, in limited locations, including the ability to meet customer electricity needs by managing power flows from one distribution feeder to another. Planners generally seek to build capacity in consideration of the single largest contingency, which is the sudden loss of the largest generator, regional transmission line, or interconnection.

Problems in system adequacy, also called capacity deficiencies, can lead to outages if (1) system operators activate emergency procedures such as rolling blackouts to avoid further system overload and catastrophic failure, or (2) if the loss of a key system element results in serious overloads, cascading equipment failure, and potentially widespread blackouts. While electric system planners and operators work to avoid such events, the needs for generation, transmission and distribution (T&D) capacity additions to meet increases in electricity demand have forced some utilities to take precautionary emergency actions more routinely than in the past (Arthur D. Little, Inc. 2000).

The availability of redundant generating and transmission capacity has made those portions of the system more robust than the distribution system. However, the recent restructuring of electric power markets and regulations, and resulting increases in long-distance power transfers, have put pressure on traditional strategies and procedures for maintaining system reliability. For example, the number of times that the transmission grid was unable to transmit power for contracted transactions jumped from 50 in 1994 to 1,494 in 2002 (Apt et al. 2004).

In addition to redundant capacity, the electric system also uses operating procedures to provide reliable service in the event of sudden disturbances. These procedures are needed because power flows reroute at close to the speed of light whenever power system conditions change (e.g., due to changes in electricity supply, demand, or weather-related events). For example, operators count on sufficient "spinning" reserves to supply immediate replacement for any generation failure.

Problems in system operational reliability can usually be classified as faults and failures. Faults are caused by external events, such as tree contact, animal contact, lightning, automobile accidents, or vandalism. Failures are caused by an equipment malfunction or human error not linked to any external influence.

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16 North American Electric Reliability Council *2006 Long Term Reliability Assessment – The Reliability of Bulk Power Systems in North America* October 2006

"Both faults and failures can cause outages. These outages can be short, lasting less than 15 seconds and quickly resolved by automatic switching equipment. When a fault or a failure results in a longer outage, it typically involves damage to equipment such as a transformer that must be repaired or replaced before service can be restored. The time required for such remedies can range from hours to days or weeks. Faults and failures, rather than capacity deficiencies, are the causes of most outages. Outages created by faults and failures in generation are rare. While transmission faults are somewhat more common, **94% of all power outages are caused by faults and failures in the distribution system** (Arthur D. Little, Inc. 2000)." (Emphasis added.)

DG offers the potential to increase system reliability, but it can also cause reliability problems, depending on how it is used. Often the difference between improving the system and causing problems if a function of how the DG is integrated with the grid, as noted in a review of critical power issues in Pennsylvania:

"In general, distributed generation can increase the system adequacy by increasing the variety of generating technologies, increasing the number of generators, reducing the size of generators, reducing the distance between the generators and the loads, and reducing the loading on distribution and transmission lines. ... Distributed generation can also have a negative impact on reliability depending upon a number of factors that include the local electrical system composition as well as the DG itself. These factors include DG system size, location, control characteristics (including whether the DG is dispatchable), the reliability of the fuel supply, and the reliability of the DG unit itself (Apt and Morgan 2005)."

2.2 Measures of Reliability (Reliability Indices)

Reliability indices are used by system planners and operators as a tool to improve the level of service to customers. Planners use them to determine the requirements for generation, transmission, and distribution capacity additions. Operators use them to ensure that the system is robust enough to withstand possible failures without catastrophic consequences.

2.2.1 Generation

Reliability is measured using the available data, which varies across utilities and across system components. One metric universal to all utilities is the loss-of-load probability (LOLP).

"Overall system reliability is often expressed as a loss-of-load probability, or LOLP. Although based upon a probabilistic analysis of the generating resources and the peak loads, the LOLP is not really a probability. Rather, it is an **expected value** calculated on either an hourly or daily basis. A typical LOLP is "one day in ten years" or "0.1 days in a year." This is often misinterpreted as a probability of 0.1 that there will be an outage in a given year. Loss-of-load probability characterizes the adequacy of generation to serve the load on the system. **It does not model the reliability of the transmission and distribution system where most outages occur** (Kueck et al. 2004)." (Emphasis added.)

Note that the LOLP is a function of the generation and peak loads – it does not include any failures in the T&D systems.

2.2.2 Transmission

Transmission failures are relatively rare and indices are not typically used to keep track of transmission line failure rates. However, at least one reliability council, East Central Area Reliability (now a part of Reliability First along with other reliability coordinators), calculates an availability that is a function of outage duration and number of circuits (East Central Area Reliability Coordination Agreement 2000). Rather, the system is designed and operated so that there is always additional transmission capacity in place to handle any unexpected line failures.

> "The bulwark of reliability for bulk power transmission systems has long been the use of "worst single contingency" design and operation-- often referred to as the "n-1" principle or criterion. It's kind of the "prime directive" of reliable power system operation. In short, it means that the system is planned and operated in such a way that it can sustain the worst single disturbance possible without adverse consequences-- consequences like overloads on other facilities, instability, or loss of firm customer load. The contingency is usually the sudden outage of a key high voltage transmission line or major generating unit (Loehr 2001)."

2.2.3 Distribution

Other reliability metrics are based upon customer outage data, and the vast majority of these outages reflect faults and failures in the distribution system. These data describe how often electrical service was interrupted, how many customers were involved with each outage, how long the outages lasted, and how much load went unserved. Industry indices are defined in Institute of Electrical and Electronics Engineers (IEEE) Standard 1366.[17] The most commonly used are listed here.

SAIFI, or system average interruption frequency index, is the average frequency of sustained interruptions per customer over a predefined area. It is the total number of customer interruptions divided by the total number of customers served.

SAIDI, or system average interruption duration index, is commonly referred to as customer minutes of interruption or customer hours, and is designed to provide information as to the average time the customers are interrupted. It is the sum of the restoration time for each interruption event multiplied by the number of interrupted customers for each interruption event divided by the total number of customers.

CAIDI, or customer average interruption duration index, is the average time needed to restore service to the average customer per sustained interruption. It is the sum of customer interruption durations divided by the total number of customer interruptions.

A reliability index that considers momentary interruptions is MAIFI, or the momentary average interruption frequency index.

MAIFI is the total number of customer momentary interruptions divided by the total number of customers served. Momentary interruptions are defined in IEEE Standard 1366 as those that result from each single operation of an interrupting device such as a recloser.

[17] The equations used to calculate these indices are included in Definitions and Terms.

Unfortunately, it is very difficult to compare these indices from one location to another or from one utility to another because of differences in how they are calculated. Some utilities exclude outages due to major events, or normalize their results for adverse weather. For the SAIDI calculation, some utilities consider an outage over when the substation is returned to service and others consider it over when the customer is returned to service, a difference in approach that can change the SAIDI by a factor of two. Some utilities use automatic data collection and analysis while others rely on manual data entry and spreadsheet analysis.

Depending upon the utility, momentary outages may be classified as a power quality event rather than a reliability event. Less often used indices include ASIFI, the Average System Interruption Frequency, and ASIDI, the Average System Interruption Duration. Both of these factors incorporate the magnitude of the load unserved during an outage. However, less than 10% of utilities track these indices (McDermott and Dugan 2003). Considering that the data collection and reporting of reliability indices vary over a broad range, their usefulness in assessing DG effects may be limited.

Another common reliability index is referred to as "nines." This index is based upon the expected minutes of power availability during the year. For example, if the expected outage is 50 minutes per year, the power is 99.99% available or four nines. However, if this index is calculated using the LOLP it won't reflect outages in the T&D systems. If the nines are calculated based on the SAIDI, the nines index will give some indication of the average system availability, but not the availability for any particular customer.

> "Conventional bulk supply systems, from a service interruption perspective, deliver power with reliability in the range of 99.0% up to 99.9999% (also referred to as "two nines" up to "six nines," respectively) and average reliability being about three to four nines, or 99.9% to 99.99%. Rural electric customers typically experience the least reliable power in the range of two or three nines. Urban customers served by networks typically have the highest reliability with five or six nines (Gellings et al. 2004)."

Considering that the data collection and reporting of reliability indices vary over a broad range, their usefulness in assessing DG effects may be limited.

2.3 DG and Electric System Reliability

DG can be used by electric system planners and operators to improve reliability in both direct and indirect ways. For example, DG could be used directly to support local voltage levels and avoid an outage that would have otherwise have occurred due to excessive voltage sag. DG can improve reliability by increasing the diversity of the power supply options. DG can improve reliability in indirect ways by reducing stress on grid components to the extent that the individual component reliability is enhanced. For example, DG could reduce the number of hours that a substation transformer operates at elevated temperature levels, which would in turn extend the life of that transformer, thus improving the reliability of that component.

2.3.1 Direct Effects

DG can add to supply diversity and thus lead to improvements in overall system adequacy. DG's contribution is often assessed by comparing the DG solution to the traditional solution. In this traditional comparison, emphasis is often placed upon the reliability of the DG system itself, and the argument is sometimes made that the DG capacity cannot be counted because it is not 100% reliable. However, there are two other factors that must be taken into consideration for this comparison to be useful. First, multiple DG units provide an element of diversity that has an improved reliability compared to a single unit, and second, the traditional alternatives are also not 100% reliable.

> "Multiple analyses have shown that a distributed network of smaller sources provides a greater level of adequacy than a centralized system with fewer large sources, reducing both the magnitude and duration of failures. However, it should also be noted that a single stand-alone distributed unit without grid backup will provide a significantly lower level of adequacy (Apt and Morgan 2005)."

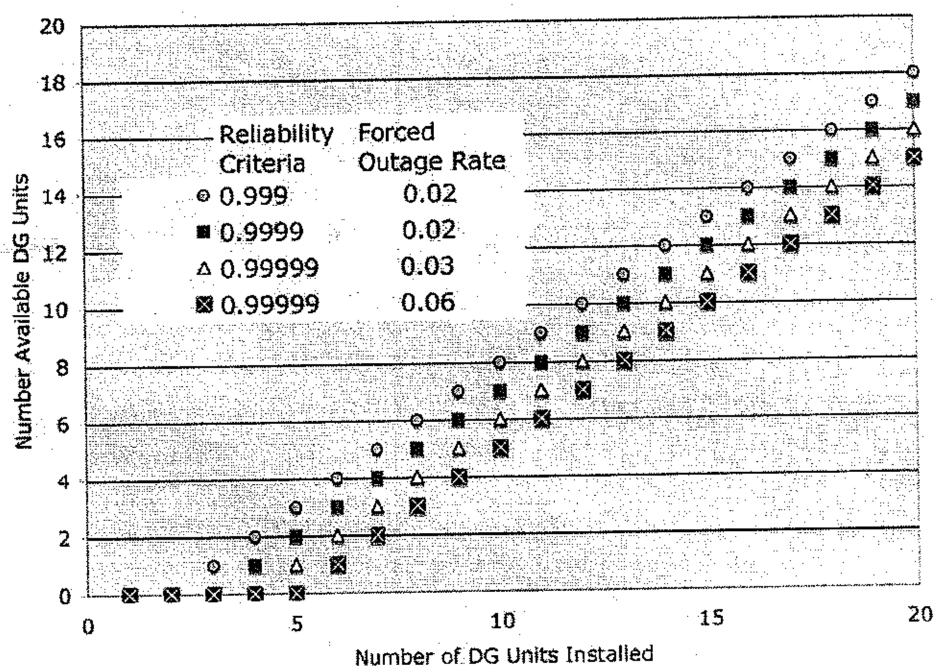
Traditionally, as load on a feeder grows, additional supply must be provided to maintain system reliability. The additional supply is usually provided to the load by adding another feeder or increasing the capacity of the local substation.

The capacity contribution that can be made by multiple DG units is shown in Figure 2.1 for a simplified case where all the DG units are the same size and have the same forced outage rate (Hadley et al. 2003). Figure 2.1 indicates that as the reliability criteria is relaxed from 0.9999 to 0.999, for an unchanged DG unit forced outage rate of 2%, the number of DG units that can be counted as "available" increases. Figure 2.1 also shows that as the DG unit forced outage rate increases from 3% to 6% for a fixed reliability criteria (.99999 in this example), the number of DG units that can be counted as "available" decreases.

As shown, the diversified system reliability is a function of the reliability of individual units, among other factors. A study of actual operating experience determines how DG units perform in the field (Energy and Environmental Analysis, Inc. 2004a). Study results include forced outage rates, scheduled outage factors, service factors, mean time between forced outages, and mean down times for a variety of DG technologies and duty cycles. The availability factors collected during this study are summarized in Figure 2.2. Although the sample size for the DG equipment was smaller than that for the central station equipment, the availability of the DG is generally comparable to that of central station equipment.

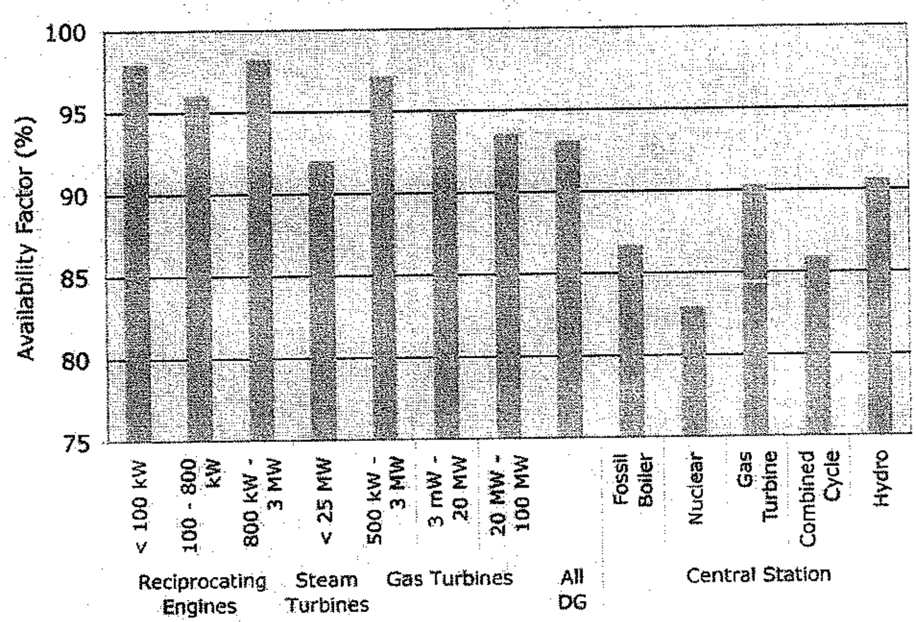
Other statistical techniques, such as Monte Carlo simulations, can be used to assess DG in more complicated cases. One such study evaluated a case with several DG systems running in parallel within a central system and calculated the system margin and the average amount of unsupplied loads. The results showed that DG can enhance the overall capacity of the distribution system and be used as an alternative to the substation expansion to meet expected demand growth (Hegazy et al. 2003). Several other analysts have also created models that acknowledge this more complete and complex situation of diversified sources, each with their own reliability characteristics (Chowdhury et al. 2003). From Apt and Morgan (2005):

Figure 2-1. The Availability of DG Units is A Function of the Number of Units, Specified Reliability Criteria, and the Equipment Forced Outage Rate[18]



18 Created by ORNL based on an equation shown in S.W. Hadley et al, "Quantitative Assessment of Distributed Energy Resource Benefits," ORNL/TM-2003/20, Oak Ridge National Laboratory, May 2003

Figure 2-2. A Comparison of Availability Factors for DG Equipment and Central Station Equipment



Source NERC GAR 1997-2001

"In addition to changing the adequacy of the system at the individual facility or distribution system level, it is possible that widespread use of grid-connected DG could affect the adequacy of the overall power system. Models comparing centralized with completely distributed system architectures show a dramatic improvement in adequacy for the distributed systems, particularly under stress conditions. Zerriffi et al. (2005) compared the results of transmission system failures on two 2,850 MW peak load systems. The first was a central generation system with 32 generators with capacities from 12 to 400 MW. The second met the load with 500 kW natural gas fired distributed generators. In reliability models run with failure rates appropriate to current generation and transmission components, the distributed generation system had roughly 25 times the reliability of the central generation system.[19] (These results compare a central generation system with 20% more capacity than load to a DG system with 1.6% more capacity than load [Zerriffi et al. 2005].)"

"An examination of systems with mixed centralized and distributed generation shows that the potential reliability benefits depend on a mix of factors, particularly the reliability characteristics of the centralized generating technologies being replaced versus those being kept, the reliability characteristics of the distributed technology, and the degree of DG penetration (Zerriffi 2004)."

Brown and Freeman (2001) made a detailed model of four utility feeders, connected with normally open tie points. In this test system, based upon an actual utility system, SAIDI improvements ranged from 5%

19 The reliability was measured in this study using a Loss of Energy Expectation (MWh/year)

to 22% with the addition of DG on just one of the four feeders. The reliability of the other feeders was improved because feeder tie operations that were previously blocked by high load levels became possible after the DG was added to serve a portion of the load (Brown and Freeman 2001).

Hegazy et al. (2003) modeled a feeder with five DG systems of varying failure and repair rates using a Monte Carlo technique. Using the unserved load as a reliability measure, the results showed that DG can enhance the overall capacity of the distribution system and can be used as an alternative to the substation expansion in case of expected demand growth (Hegazy et al. 2003).

2.3.2 Indirect Effects

DG has the potential to reduce the number of outages caused by overloaded utility equipment. For example, during peak load situations, higher currents may lead to thermal loss-of-life in transformers and other equipment, which in turn may lead to service interruptions. These outages are usually caused by sudden equipment failures that lead to increased loads on the remaining equipment. Such overload failures account for about 10% to 30% of all outages, depending on the utility and the region. DG can be used to reduce the number of times per year when distribution equipment is used near nameplate ratings, and thus could reduce the frequency of equipment failures and subsequent outages (EPRI 2004; McDermott and Dugan 2003).

2.4 Simulated DG Impacts on Electric System Reliability

Simulation modeling is a valuable tool that can be used to explore the potential impacts of DG on electric systems. For example, a Virtual Test Bed simulation platform suite was constructed in one detailed study to examine both power quality and reliability issues associated with DG installations (GE Corporate Research and Development, 2003). The Virtual Test Bed models the utility's power delivery system, the loads, and the DG. In this study, parametric analysis is used to examine the influence of the amount of DG on a feeder, the location of the DG relative to the loads, (lumped at the beginning, middle, or end of the feeder, or uniformly distributed along the feeder), inverter-based and rotating DG technologies, DG local voltage regulation strategies (either operation at a power factor of 1.0 or the DG provides voltage regulation based on local conditions), two radial feeder lengths, and the presence or absence of capacitor banks on the feeder.

The analysis of protection and reliability in this study included: transient response and fault behaviors (capacitor switching and fault behaviors); reclosing; anti-islanding scenarios; and power systems dynamics and stability. Some of the conclusions from this analysis, which focused on the behavior of DG units with power electronics, were that:

> "A fault analysis found that the fault current contribution of a standard induction motor is usually much larger than that of current controlled inverter-DG. … the DG, in this example, provides some damping to high-frequency oscillations. Other findings include:
>
> - Local distribution system dynamics are most affected by DG trips.
> - Distributed generation controls do not have a major impact on local dynamics when the connection to the host utility is maintained.

- Anti-islanding schemes (of the type tested here) appear to be effective at destabilizing islands containing multiple DG units and loads with relatively complex dynamics.
- Voltage and power regulation tend to act contrary to the anti-islanding schemes.
- Widespread penetration of DG units at the load appears to be benign with respect to system response to bulk system disturbances.
- Anti-islanding schemes (of the type tested here) appear to have little impact on system response to bulk system disturbances.
- Aggressive tripping of DG units in response to under voltages appears to present a substantial hazard to the bulk system, and was shown to bring down the entire U.S. western system in one extreme case (GE Corporate Research and Development, 2003)."

Another analyst used a probabilistic reliability model to compare the options of adding DG or adding another feeder to a local distribution network. Using the Expected Energy Not Served as the reliability index, this model is able to optimize both the size and location of alternative DG units. The input for this model includes values for the annual failure rate of each system component, the repair time, and switching times. For example, for the network studied, substations were given failure rates of 0.02 occurrences per year, line sections of 0.04 to 0.12 occurrences per year, and DG of 5 occurrences per year, with repair times of 4 hours for the network resources and 50 hours for the DG resources. For this network, an additional feeder was able to reduce the Energy Not Served from over 17 MWh per year to less than 5 MWh per year. Three possible DG configurations were identified that provided that same level of reliability (Chowdhury et al. 2003). This study is enlightening because it recognizes that DG can improve system reliability even if it is not 100% reliable itself, that is, that physical assurance requirements are no more appropriate for DG resources than for any other network resource used to provide reliable service.

In 2003, Oak Ridge National Laboratory (ORNL) performed a study entitled "Quantitative Assessment of Distributed Generation Resource Benefits." In this study, ORNL quantified the benefits of system reliability in terms of a reduction in the LOLP of DG (Hadley et al. 2003). Reliability of the Pennsylvania/New Jersey/Maryland Interconnection (PJM) system was simulated across multiple scenarios of differing generation unit sizes. The study shows that improvement in the LOLP is achieved when generation expansion needs are met with ten small plants compared to a single large plant of the same size. For example, in one scenario, generation expansion was designed to be met by a new 100 MW single unit and in the alternative scenario as ten 10 MW units. Many other paired scenarios of single or multiple units of generation capacity were also analyzed.

The study results indicate that the LOLP for each pair of scenarios was always lower in the scenario with the higher number of units. This suggests that a system in which capacity expansion is comprised of many DG units, rather than one central station power plant, can provide more reliable service to customers. The study draws the following conclusions:

> "Based on the ... analysis there is a small but positive value to having capacity added at the unit size of DG as opposed to typical central station size. The main beneficiary may be society. If reserve margins are fixed by PJM at a certain percentage of demand, or by the largest single contingency, then society will benefit by increased reliability at the same amount of capacity. This can also lead to lower electricity prices since high cost plants will not be called upon as

often. If, however, the ISO chooses to lower the required reserve margins, then utilities may benefit by not having to have as much reserve capacity on hand, through either ownership or the capacity market (Hadley et al. 2003)."

The study also indicates that DG units can be used to improve system reliability even though each individual unit is less than 100% reliable. That is because the same rules of redundancy and diversity that applies to central station plants, or any other component of the power system, also applies to DG.

2.5 Possible Negative Impacts of Distributed Generation on Reliability

In light of the many potential benefits associated with DG, there has been a large body of work devoted to addressing a number of concerns with regard to the impact of DG on system stability and safety. Standards agencies, such as the IEEE, have promulgated interconnection standards to protect both the grid and the DG equipment. Some states have instituted interconnection rules that serve the same purpose. However, some of the equipment required to meet these standards or other utility-imposed rules can be costly, especially if used for smaller scale DG projects. Research is on-going to find better solutions and to optimize the use of DG in the grid.

Some researchers are also examining possible common cause failure modes that could become important if the use of DG grows. One DG failure mode, the loss of local natural gas supply, is also important for central generation as more central station power plants use that relatively clean fuel.

2.5.1 Traditional Power System Design, Interconnection and Control Issues

The electric system has been designed to accept power input from large generating stations that are synchronized with each other and the rest of the grid. That is, the wave form of the electricity produced by each central generator matches the wave form of the electricity traveling on the grid. Large transmission lines carry this electricity to substations, where smaller distribution lines carry the electricity to customers. The vast majority of these distributions systems were designed for one-way flow of electricity (called radial), from the substation to the customer. This design is reflected in the protection devices that open and close switches when a tree limb falls on a power line or when lightning strikes a part of the system. A few urban distribution systems have been designed for two-way flow through the lines (called network), so that if one line fails another line can be used to deliver electricity to the customers. Network systems are more complex to operate, but many of their design features may be useful as DG systems are added in greater numbers to radial systems.

2.5.2 Fault Currents

A fault occurs when electricity travels along unintended pathways, for example along a tree branch that falls across two wires. Most faults on overhead distribution lines are temporary, such as an arcing current to the ground that might be initiated by a lightning strike. These temporary faults can be corrected by simply turning off the current to the affected wire(s) and letting the arc extinguish. Because the system itself has not been damaged, the current can then be turned on again. Automatic protection systems are designed to do just that, turn off the current when a fault occurs and then turn it back on after the arc is gone so that customer service interruptions are as short as possible. If a DG unit is providing power to the system at a location between the protective switch and the fault, and no appropriate communication or protection equipment has been installed, it can continue to provide current to the fault so that the fault continues. The longer a fault lasts, the more likely it is to cause damage to both the distribution system and to customer equipment (Dugan and McDermott 2002).

> "Distributed units can provide voltage support on distribution feeders. However, this can complicate service restoration after a fault. If the load becomes dependent upon the distributed unit for voltage but the DG unit must disconnect due to a fault, the utility may not be able to maintain voltage at acceptable levels as the fault is cleared, necessitating changes in procedures and possible delays in restoring power (Kashem and Ledwich 2005)."

Distribution-level instabilities can also be related to DG, as explored by Cardell and Tabors (1998).

> "Cardell and Tabors (1998) found that installing generation at the distribution level can decrease the stability of the system. This is the result of changes in designed power flow direction as well as in the electrical characteristics of the lines themselves ..., which can affect the degree to which connected generators and loads can interact with one another. Under certain combinations of distributed generation technologies, the system can become unstable when a disturbance (such as a line or generator outage) is introduced. .... The authors argue that these results show the need for new methods to control and stabilize systems that have numerous distributed generators."

A general description of the issues here is adapted from Apt and Morgan (2005).

> **Location.** DG units located upstream of a system failure point cannot mitigate the impact on customers located downstream of the failure location. The DG placement on a distribution feeder can also determine whether there will be stability and power flow problems.
>
> **Dispatchability**. Intermittent resources, such as photovoltaics or wind, can aid in reducing power needs, but can have a negligible impact on reliability needs due to their lack of dispatchability. Similarly, a DG unit that is tied to a thermal load may not be independently dispatchable.
>
> **Controllability**. Technologies with fast switching times can potentially provide a wider variety of reliability support. On the other hand, if a technology is installed that has a slower response time, it may be necessary to modify the operation of other components in the system, potentially degrading one measure of reliability even as another is increased.
>
> **Fuel and Unit Reliability**. The reliability characteristics of the distributed resource itself, including the reliability of the fuel supply, will also determine its contribution to system reliability (Apt and Morgan 2005).

2.6 Approaches to Valuing DG for Electric System Reliability

The economic benefits of using DG to improve electric system reliability can be estimated by determining the avoided costs of traditional forms of investment in electric reliability. Under this approach, the net benefits of installed DG to the utility is the benefit from deferred generation and T&D investments, net the costs associated with installing, operating, maintaining, administering, coordinating, scheduling, and dispatching DG units. Not many utilities assess DG in this way when considering expansions and/or upgrades in T&D equipment. If many did it is likely there would be more instances where the benefits of

DG would outweigh the costs, although it is important to remember that the financial attractiveness of DG is highly dependent on local conditions, costs, and resources.

Ownership and type of business model is an important consideration in the valuation of the potential benefits of DG. For example, when used for reliability purposes, utilities generally require customer-owned DG to provide performance guarantees and/or physical assurances that the units will be reliable and available when needed, especially at the time of the peak demand. Such guarantees are normally not required for investments in utility-owned generation, transmission, and distribution equipment. These requirements add to the costs and risks of DG ownership.

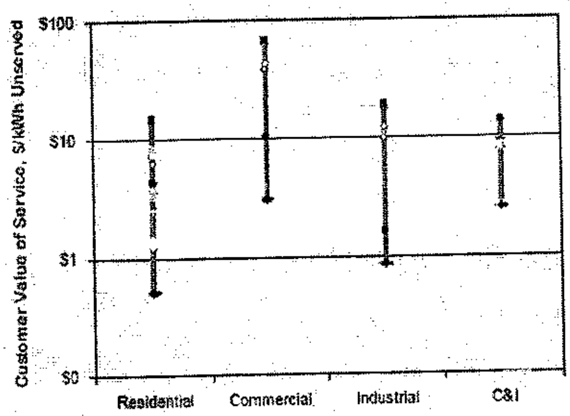
In certain situations it is possible that there could be a cost justifiable basis for utilities to offer DG owners capacity payments for units that are able to be dispatched by grid operators during times of system need. Such payments could support the acquisition of redundant DG units to ensure availability and address utility interests in performance guarantees.

Energy and Environmental Economics (E3) developed an approach for evaluating the economic potential for renewable DG applications for municipal utilities (Energy and Environmental Economics, Inc., 2004). The study used estimates of value-of-service (VOS) and unserved energy to assess the economic benefits of DG for specific grid locations. The E3 approach is similar to the LOLP methodology used in Hadley et al. (2003), but the E3 approach included an explicit VOS component, which is intended to quantify the value of improved reliability.

The E3 methodology comprises two steps. The first step is to compute a weighted VOS based on the proportion of each customer class served on the feeder or system affected by the DG, and the VOS for each customer class, on a kWh basis. The VOS estimates are derived from studies that query customers about how much they would be willing to pay to avoid an outage. The VOS estimates are usually much higher than standard electricity rates, which can be interpreted to mean that most customers are willing to pay more for electricity than they currently do. The report cites VOS values in the range of $5 to $30 dollars per kWh in historical survey studies (Energy and Environmental Economics, Inc. and Electrotek Concepts, Inc., 2005). Figure 2.3 provides a range of the VOS values used in this study; note the logarithmic scale used to portray the wide range of values from less than $1 to almost $100/kWh unserved.

The second step calculates the change in unserved energy. In this example, unserved energy is calculated using an in-depth engineering analysis designed to calculate the number of hours in which a defined system will exceed the emergency ratings on a particular distribution feeder. This value is calculated for two contrasting cases. The first is a status quo case and the second reflects the introduction of a number of small renewable DG facilities.

Figure 2-3. Range of Vos Values Used in Municipal Planning Study



Source Energy and Environmental Economics, Inc. and Electrotek Concepts, Inc., 2005

The E3 study presents results for a number of detailed DG scenarios, including various levels of installation of photovoltaic systems, combined heat and power additions at critical facilities or substation sites, and various configurations of peaking DG units. Each case presented positive results associated with installation of DG as summarized in Table 2.1.

Table 2.1. Value of Reliability Improvement (Year 2004)

Case	"Overload kWh Normal"	Δ "Overload kWh Normal"	p(outage)	VOS ($/kWh)	VRI
No DG	54,847	NA	0.27%	$8	NA
4 MW Distributed PV	40,093	14,754	0.27%	$8	$319
2 MW CHP Peaker @ VA	27,821	27,026	0.27%	$8	$584
2 MW CHP Baseload @ VA	25,401	29,446	0.27%	$8	$636
10 MW Optimal Gens	17,295	37,552	0.27%	$8	$811
10 MW CHP @ VA Hosp	24,909	29,938	0.27%	$8	$647
10 MW CHP QR Sub	53,359	1,488	0.27%	$8	$32
Pump Regen Case	54,775	72	0.27%	$8	$2
CPAU PV Case	53,838	1,008	0.27%	$8	$22

Note that the study authors do not explicitly address the comparative costs of competing DG options or alternative investment options designed to provide identical reliability. This addition to the methodology is discussed below.

2.7 The Value of Electric Reliability to Customers

One of the reasons why customers value electricity so highly is that the cost of electric system failures can be significant. One way to value DG-related improvements in the reliability of electric systems is to determine the value of higher reliability to customers. Value-of-service is one methodology to determine the value of reliability to customers. Another approach is to assess the outage costs to customers. There are a number of recent studies of outage costs; however there are no recent studies that use outage costs to determine the value of DG to improving electric system reliability.

Recent studies generally indicate that outage costs can be as high as 100 times the average price of electricity, depending on the type of customer. Some surveys indicate the cost to be between \$0.25/kWh to approximately \$7/kWh. For example, Navigant Consulting estimates the reliability benefit from avoided downtime at \$1/kWh (Navigant Consulting 2006). A recent study by Sentech involved the review of a set of commonly cited power outage cost data ranging from \$41,000/h for cellular communications to \$6,500,000/h for brokerage operations. The Sentech study sought "to assess the cost of power outages to businesses in the commercial and industrial sectors using the best and most current data available, short of surveying a statistically significant pool of building owners."

Downtime cost components were categorized as either tangible or intangible as shown in Figure 2.4.The study used existing literature based on surveys of actual end users that covered outages of 20 minutes, 1 hour and 4 hours in duration. The data from the surveys show that the duration of an outage has a large effect on estimated downtime costs. Although all sub-sectors estimate similar downtime costs during short outages, as the duration increases, the costs identified by different commercial sub-sectors begins to vary more widely.

At the 20 minute duration, almost all commercial sub-sectors have comparable downtime costs. However, as an outage persists and food spoilage sets in, costs for restaurants (food service) and grocery stores (food sales) increase faster than for other sectors.

The next two figures from the Sentech study provide another way to illustrate these changes in the distribution of costs for commercial sub-sectors over the duration of a blackout. One can see that the share of costs experienced by food service and sales grows until it accounts for the majority of costs after four hours of outage duration. These figures also illustrate that offices incur large costs during the initial minutes of a blackout, but subsequent losses are much smaller. Presumably, this is because of the high cost of data loss and damage to computer equipment that occurs during the initial moments of a blackout; more data collection and analysis would be needed to confirm this assumption.

Figure 2-4. Costs Considered in Sentech Outage Cost Study

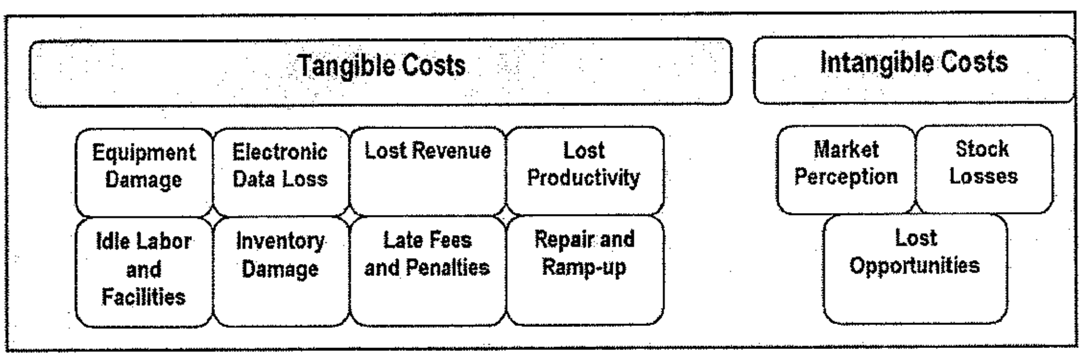


Figure.2-5. Commercial Sub sector Power Outage Costs

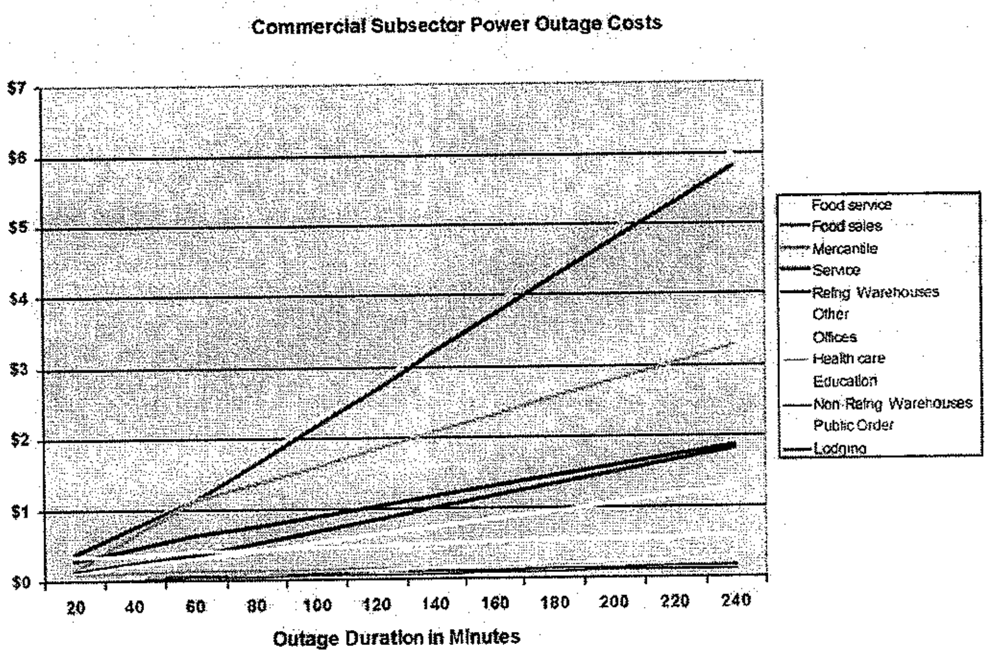
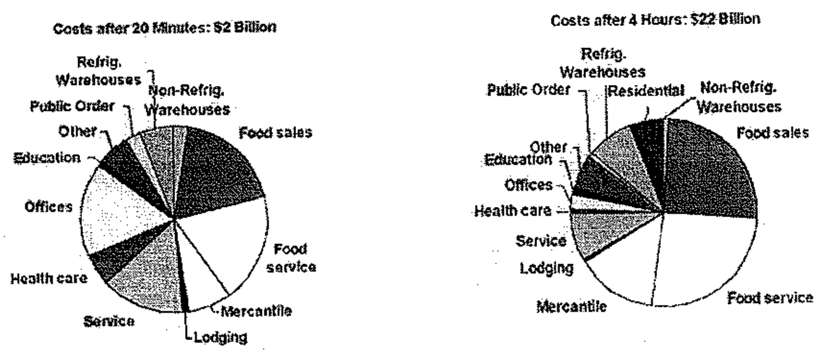


Figure 2-6. Sentech Study Outage Costs after 20 Minutes and After 4 Hours



Lawrence Berkeley National Laboratory (LBNL) recently conducted a study of the costs of power outages to the U.S. economy (LaCommare and Eto 2004). The study estimates annual losses to the U.S. economy from momentary and sustained power outages to be about $79 billion annually, with 72% of those costs affecting the commercial sector, 26% industrial, and 2% residential. The study reports that during a reliability monitoring program, several participants contributed business information to help explain the sources of outage costs:

> "...valuable insight on the often-cited statistic that an outage costs silicon-chip fabricators $1 million per event...The determining factor is whether the downtime results in the firm missing a deadline for delivery of chips that have already been sold. He pointed out that, in 2003, many firms were running at less than full capacity. Under these conditions...costs of materials lost as a

result of the outage were minimal in comparison to the financial penalties that would be associated with missing shipping delivery dates. The chip fabricator participating in our study reported that outages of even a few minutes could sometimes lead to 1 to 1.5 days of downtime, causing the firm to forego $500,000 per day in revenues. .... A related example was provided by the manufacturer of silicon-chip fabrication equipment...the manufacturer must conduct a continuous, 1,000-hour factory test, which takes about six weeks. Any interruption during this period requires restarting the entire test from the beginning....This firm reported that it had recently made a $2.5-million investment in equipment to improve electricity reliability that paid for itself in nine months, which translates into an implied cost per outage of $350,000 per event...The monetary penalties for missing deliveries are especially high in the financial services industry. For these firms, "missed" deliveries refer to financial transactions that cannot be executed...Stringent financial penalties, based in part on the value of foregone or inaccurate transactions, result from exceeding pre-specified limits...We were told of a financial clearinghouse in Texas that had experienced a $12- million loss as the result of a 30-minute outage caused by a lightning strike." (LaCommare and Eto 2004).

2.8 Major Findings and Conclusions

Electric system reliability is an aggregate measure used by electric system planners and operators to evaluate the level and quality of service to customers. One of the traditional approaches to achieving a reliable system involves building sufficient redundancy to ensure continued operations even with the loss of the largest generator or transmission line. Another involves monitoring grid operations and making adjustments to changing conditions to prevent momentary problems from cascading into local or regional outages. DG units can be used by electric system planners and operators to augment these traditional approaches to electric system reliability. While mostly customer-owned, some existing DG units are made available to utilities for operations during times of system need through various incentives and pricing approaches, including demand response. Studies show that in many instances utilities could make greater use of DG directly, and deploy units to provide peak power, voltage and VAR support, or other ancillary services to meet electric system reliability needs. However, most utilities do not own or operate DG units in this way. And, there are no standard models, tools, or techniques for utilities to evaluate DG and incorporate DG resources into electric system planning and operations.

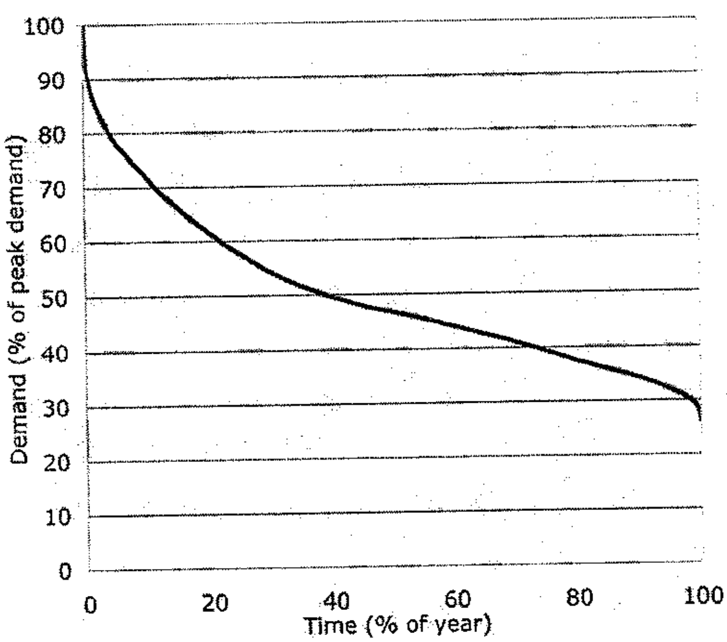
Section 3. Potential Benefits of DG in Reducing Peak Power Requirements

3.1 Summary and Overview

Electricity demand, or load, fluctuates throughout each 24-hour period. Demand is typically lowest overnight, when commercial and residential buildings are inactive. Demand typically "peaks" in mid-afternoon, with the highest system-wide peaks typically occurring during hot summer afternoons. If the 8,760 hours in each year are shown in aggregate, with the total load plotted for the year as in Figure 3.1, the number of hours each year in which demand peaks is clearly quite small. In this example, 80% of the time this feeder line is being used to about 60% of its capacity. This is a typical pattern of usage in the electric distributed system for feeder lines that serve primarily commercial and residential customers.

Local reductions in peak demand on specific feeder lines will flow "upstream" and produce demand reductions on substations, transmission lines and equipment, and power plants, thus freeing up assets to serve other needs. The economic benefits from a reduction in peak power requirements are derived primarily from deferred investments in generation and transmission and distribution (T&D) capacity. Utilities make investment decisions for generation and T&D capacity based on peak requirements. Thus, in the long run, any reduction in peak power requirements provides direct benefits to the utility in the form of deferred capacity addition/upgrade costs.

Figure 3-1. Load Duration Curve for a Typical Mixed-Use Feeder



A common method for electric system planners and operators to produce demand reductions is by using demand response (DR) programs. Demand response has been defined as:

"Changes in electric usage by end-use customers from their normal patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at time of high wholesale market prices, or when system reliability is jeopardized."[20]

DR programs are generally categorized as one of two types: (1) Price-based programs such as real-time pricing, critical peak pricing, and time-of-use tariffs; or (2) Incentive-based programs such as direct load control and interruptible rates. According to the North American Electric Reliability Council (NERC), about 2.5% of summer peak demand (20,000MW) is affected by incentive-based DR programs.[21] DG can be effective in affecting customer responses to electricity demand. A study of DR programs operated by the New York Independent System Operator (NYISO) in 2002 showed that DG was an important factor in the ability of certain participating customers in successfully reducing their demand. DG enabled these customers to continue near-normal operations while they reduced their consumption of grid-connected power, thus reducing demand at NYISO.[22]

3.2 Load Diversity and Congestion

Not all electricity-using appliances and equipment demand power from the grid at the same time. For example, residential lighting loads are greatest in the morning and evening, while commercial lighting loads are greatest during business hours. Manufacturing loads vary according to the number of shifts used in any given factory and according to the electric equipment use schedule. Considering such "demand diversity," the "peak" load is never the sum of all the connected loads on a feeder or transmission line. One guideline shows that the peak load on a feeder is approximately half of the connected load, the peak load on a substation is approximately 45% of the connected load, and the peak load on a generating station is about 41% of the connected load, as shown in Figure 3.2 (Departments of the Army and the Air Force, 1995). This trend shows that load diversity on any particular system component increases as the number of customers served by that component increases.

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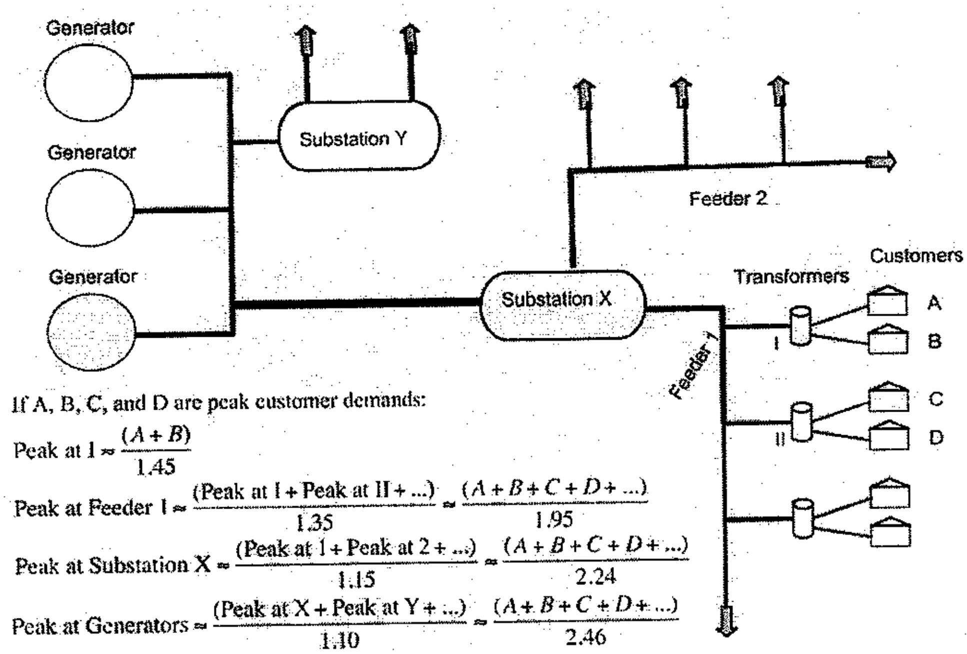
20 U.S. Department of Energy *Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them* A Report to the U.S. Congress Pursuant to Section 1252 of the Energy Policy Act of 2005 February 2006

21 North American Electric Reliability Council *2006 Long-Term Reliability Assessment – The Reliability of Bulk Power Systems in North America* October 2006

22 Lawrence Berkeley National Laboratory et al *How and Why Customers Respond to Electricity Price Variability: A Study of NYISO and NYSERDA 2002 PRL Program Performance* January 2003

Figure 3-2. Electric Demand Flow Diagram



If A, B, C, and D are peak customer demands:

$$\text{Peak at I} \approx \frac{(A+B)}{1.45}$$

$$\text{Peak at Feeder 1} \approx \frac{(\text{Peak at I} + \text{Peak at II} + \ldots)}{1.35} \approx \frac{(A+B+C+D+\ldots)}{1.95}$$

$$\text{Peak at Substation X} \approx \frac{(\text{Peak at 1} + \text{Peak at 2} + \ldots)}{1.15} \approx \frac{(A+B+C+D+\ldots)}{2.24}$$

$$\text{Peak at Generators} \approx \frac{(\text{Peak at X} + \text{Peak at Y} + \ldots)}{1.10} \approx \frac{(A+B+C+D+\ldots)}{2.46}$$

Just as there is demand diversity within the system, there is also "supply diversity." Central power plants are selected to provide power to the grid according to a dispatch order (or stack) determined by their variable costs, subject to certain constraints.[23] These constraints include start-up and shut-down costs, reliability implications, and maintenance requirements. For example, hydropower is almost always the lowest cost power, but its availability is limited by the amount of water stored behind the dam. Other plants operate outside of this dispatch order because they are outside the control of dispatchers, such as combined heat and power plants, roof-top photovoltaic arrays, and other customer-owned DG. Plants that are called on for essentially continuous operation (either because of their low variable cost and/or high start-up and shut-down costs, or because of their importance to reliability) are called base load plants. These typically include all nuclear and a major portion of coal plants. Plants are dispatched to meet the total load at any given time according to this dispatch order so that most plants operate for only a portion of the year. Note that the most expensive power supply is usually the last unit dispatched by the system operator, and is the first unit removed from the system if the load is displaced by operations of DR programs.

Although multiple power plants and transmission lines are available to provide power to any given feeder, not all of them are running or fully loaded at any one point in time. The available capacity of the supply system is limited below the actual capacity of the lines, transmission equipment, and plants in service by the need to provide a contingency allowance and maintain operating reserves. A "contingency allowance" is a prudent operating strategy that holds transmission capacity in reserve in order to continue providing service in the event that any single transmission element in use were to fail. This is often called an "N-1" operating strategy.

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23 Variable costs include fuel, variable operating costs, and emissions permits.

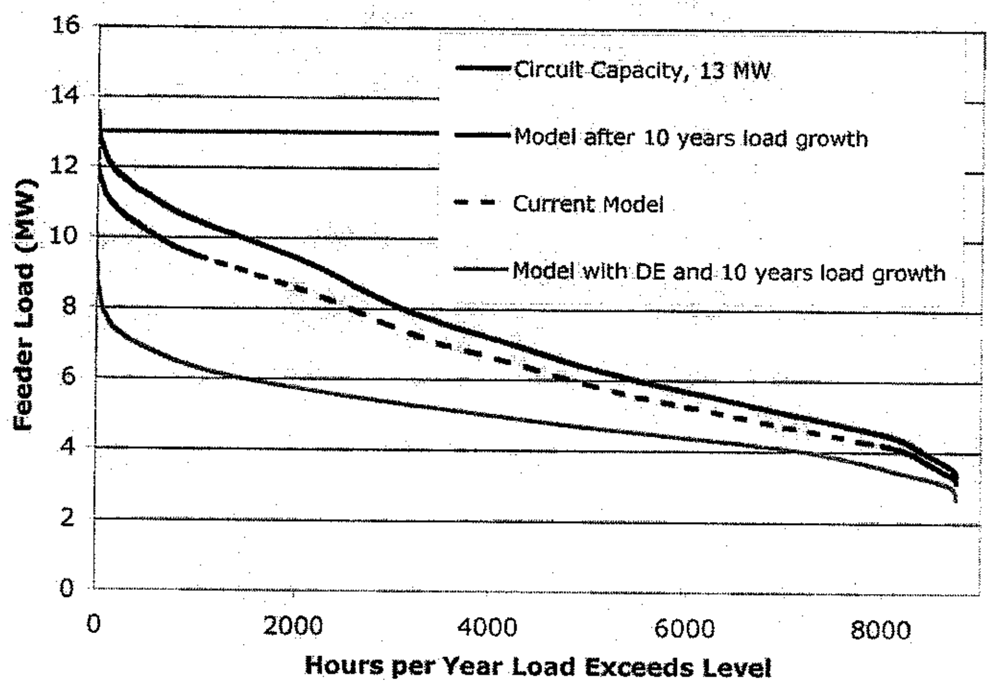
With demand growth, peak demand eventually exceeds the capacity of the supply system, or the capacity and configuration of the supply system are insufficient to allow for the most economic system dispatch to meet demand. "Congestion" occurs when the demand for electricity within some geographic boundary is greater than the combined capacity of the transmission lines serving that area and any generating stations located within that area, or when the capacity of any transmission system component prevents a dispatch that would otherwise be more economical than the constrained dispatch. (Note that this combined transmission line capacity is reduced by the required contingency allowance.) Congestion is commonly manifested in the loss of economic efficiency rather than blackouts, but its effects are nonetheless significant.

3.3 Potential for DG to Reduce Peak Load

Several utilities have evaluated using DG to reduce peak load requirements, although it is not a very common practice. A variety of methodologies have been used for these evaluations, some of them using specific data for actual feeder lines and substations, and others using more generic information. An example of such an evaluation is provided below. In some of these evaluations, it is the case that DG is the most financially attractive option; in others, DG is not. Even in those instances where it has been determined that DG is the most financially attractive option, it is not always the case that investments are made in DG. This is due to a variety of issues, including a lack of familiarity with DG technologies, tools, and techniques, and the perceived likelihood that cost recovery will be less controversial with investments in traditional T&D equipment.

A study, focused on two real Southern California Edison (SCE) circuits, showed that adding DG would reduce peak demand on the two circuits enough to defer the need to upgrade circuit capacity. Figure 3.3 shows the results for the circuit that served a mix of commercial, small industrial and residential customers. If the DG installations are targeted optimally, the deferral could economically benefit SCE and its customers, with cost savings that outweigh the lost revenues due to lower sales of electricity (Kingston and Stovall 2006).

Figure 3-3. Comparison of Projected Load on a Feeder With and Without the Addition of Distributed Generation



3.4 Market Rules and Marginal Costs

3.4.1 Organized Wholesale Markets

3.4.1.1 Impact of Demand Reductions on Wholesale Prices

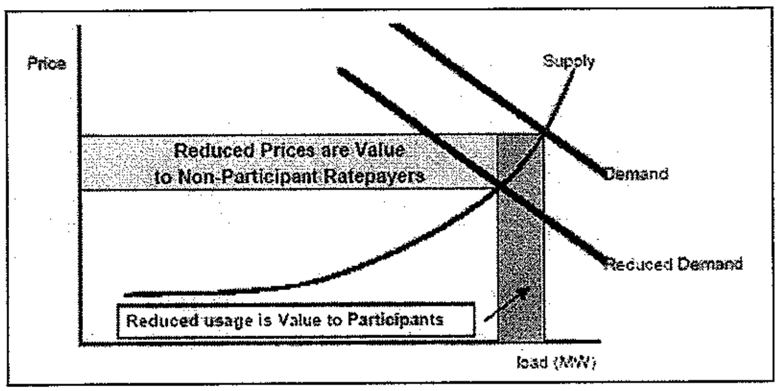
A study performed by JBS Energy for the Mid-Atlantic region notes that "...when power consumption is reduced, particularly during peak periods, the market price of electricity is reduced for all consumers." (Marcus and Ruszovan 2000). Consumers who reduce their demand for electric power derive benefits from reduced power costs as well as provide direct benefits to other customers served by the utility by reducing the marginal price of electricity for the general system as a whole.

However, as noted by Siddiqui et al. (2005), because most electricity customers receive static price signals that do not vary over time, they are not exposed to the marginal costs of generation, so that the demand curves we see in wholesale power markets today are generally inelastic with respect to wholesale prices. This study goes on to find that, in markets that expose customers to time-varying rates, there is a "demand response" to changes in electricity prices. The extent of this response is affected by the magnitude of the change in price. Since operating DG is one way for customers to respond to changes in prices, it is possible for DG to have a beneficial effect on the prices received by all customers due to reductions in demand in wholesale markets, which reduces the need to run the most expensive power plants.

This point is amplified in the JBS study, which states:

> "In the old world, in a given hour the marginal cost of energy of a bundled utility was the price of the last most expensive unit of the utility's generation. But the cost was only incurred for that last unit. Thus, the marginal cost was the value of demand reduction, because the last unit's generation was avoided. In the new world of power pools (in places such as PJM, New York, New England, California, and Alberta) the price for all units of energy traded through the pool is set on an hourly basis by the market-clearing bid price for the last unit (of generation or load reduction) bid in to serve demand. As demand rises, the total revenue received by all generators rises. Thus the value of demand reduction from the perspective of ratepayers is not just the market price (bid price of the last unit). It is the market price plus the increase in the bid price multiplied by all other generators except the last unit. ... As demand rises, particularly in peak periods, the price of energy rises relatively rapidly. If demand can be reduced, for example due to the installation of more efficient appliances, the price will tend to fall as demand falls, benefiting not only the customer whose demand is reduced but all other customers who receive the lower prices of spot market energy. Figure 3.4 shows the effect graphically for a given hour. The reduction in usage multiplied by the original market price is a benefit to the customer(s) reducing load. The reduced price multiplied by the usage after the reduction benefits all other loads. (Marcus and Ruszovan 2000)." [24]

Figure 3-4. Market Price and Value of Load Reduction



The approach used in the JBS study is to consider a simple supply curve of all generating resources (Figure 3.4 above) to derive the value of reduced load (by comparing the supply mix used to serve historical peak loads to the supply mix necessary to serve that load reduced by 2% to 3%) in the Pennsylvania/New Jersey/Maryland Interconnection (PJM). The supply curve is the stack of generating units available to meet load throughout the region in merit (cost) order. The price of power with and without demand reduction in each hour is determined from the marginal cost of the last unit to serve load, which is itself determined by the intersection of demand and the supply curve. The value of reduced load to all customers can then be calculated for a given reduction in demand by calculating the difference in pool revenues as shown in the example in Table 3.1.

24 Excerpted from Marcus and Ruszovan 2000. Original figure designation was Figure 1.

Table 3.1. Value of Reduced Load Calculated by Pool Revenue

Calculation Example			
	Quantity (MW)	Price* ($/MWh)	Pool Revenue ($/hr)
Load	40,000	$45,54	1,821,454
Reduced Load	39,000	$41.28	1,609,808
Difference	1,000		211,646
Value of unhedged load reduction			211,646
Value of 50% hedged load reduction**			128,591
* Summer/winter weekday, $4.00/MMBtu gas ** 50% of VLR unhedged + 50% of original market price			

MMBtu= million British Thermal Units
MW= megawatts
MWh= megawatt hours
VLR= value of reduced load

The study points out two important caveats about this approach. First, while the study accurately represents the PJM spot market, many customers are not fully exposed to this volatile market. They are instead "hedged" with contracts or direct supply options. For example, a fully contracted customer with a fixed price would be unaffected by the reduction in energy prices driven by load reduction. Second, the long-term effects of price reduction may be muted as less generation is built which "could create some countervailing upward price pressure." (Sebold et al. 2005.)

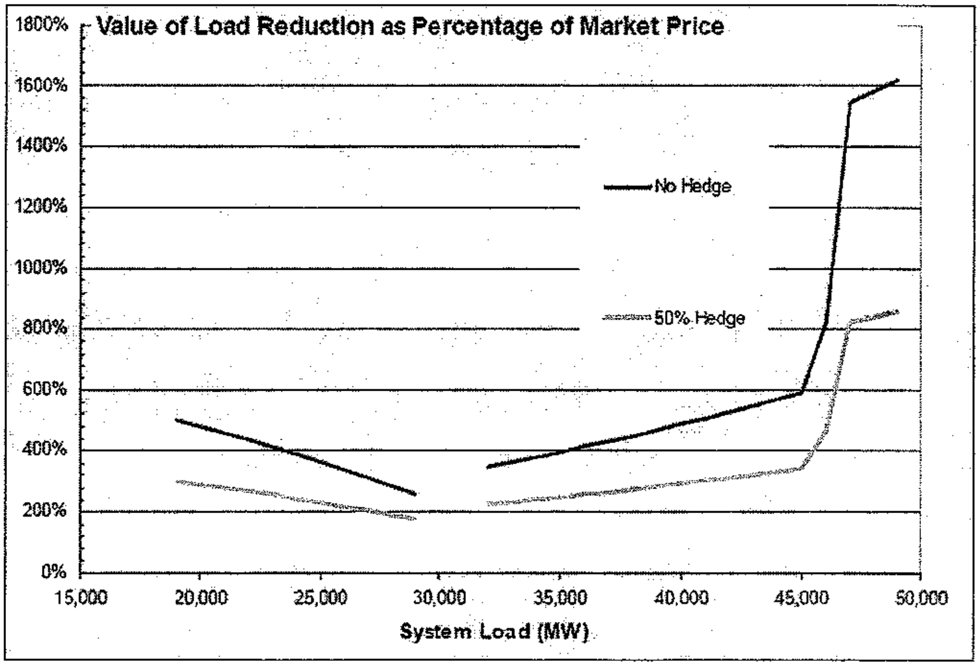
In an attempt to counteract these issues, the JBS study authors analyzed two cases. Figure 3.4 shows the "no-hedge" case which shows full value, and a "50% hedge" case in which the impact is halved.[25]

Thus, the JBS study shows us that the market rules in organized wholesale markets, and the extent to which supply prices are hedged, will determine the market savings for power purchasers. In areas where elevated power supply prices are passed on to ratepayers, the ratepayers will benefit from the savings. However, savings due to reductions in the marginal price in organized wholesale markets do not necessarily accrue to the ratepayers. Depending upon the local rate schedules, distribution utilities may be unable to pass elevated peak load costs on to ratepayers. In these cases, since the cost of peak power would never have been borne by the ratepayers to begin with, those ratepayers would not realize any savings. Rather, in these areas, any such savings would remain with the utility.

Figure 3.5 shows that, including the impact on the market price, even with 50% physical hedging, the value of load reduction is at least 170% of the value of energy at all loads. Above 30,000 MW, both prices and the value of conserved energy rise rapidly, but the value of load reduction rises faster. The value of load reduction rises from 217% to 294% of the market price of energy from 31,000 to 40,000 MW and then rose faster to reach 3-1/2 times the market price at 45,000 MW and 8 times the market price at 50,000 MW. Without hedging, the figures are even higher (Marcus and Ruszovan 2000).

Figure 3-5. Value of a 1000 MW Load Reduction as Percent of Market Price

25 The gap at 30,000 MW is shown on Figure 2.5 because of the shift between two separate cost curves. This study also included benchmark comparisons of the model results to actual market prices and an advanced price model that included time-of-use features.



3.4.1.2 Impact of Demand Reductions on Congestion Costs

Implicit in energy prices is the cost of transmission congestion and losses. This is especially the case in markets with locational marginal pricing (LMP) schemes. Transmission congestion constrains less expensive power from reaching high demand locations. Higher cost generation in the constrained regions are dispatched to relieve congestion and to serve the incremental load. Thus consumers in constrained regions pay more for power as a result of transmission congestion. Congestion costs can be significant in many markets and deployment of DG to relieve congestion could result in savings for all customers. Table 3.2 shows historical congestion costs paid by customers in organized wholesale markets.

Table 3.2. Historical Congestion Costs in Some Deregulated Markets ($ billion nominal dollars)

	2000	2001	2002	2003	2004	2005
PJM	0.13	0.27	0.43	0.50	0.75	2.09
NYISO	0.51	0.31	0.52	0.69	0.63	NA
ERCOT	NA	NA	0.25	0.41	0.28	NA

ERCOT= Electric Reliability Council of Texas
NYISO= New York Independent System Operator
PJM= Pennsylvania/New Jersey/Maryland Interconnection
Source: State of the Market Reports issued by each ISO/RTO

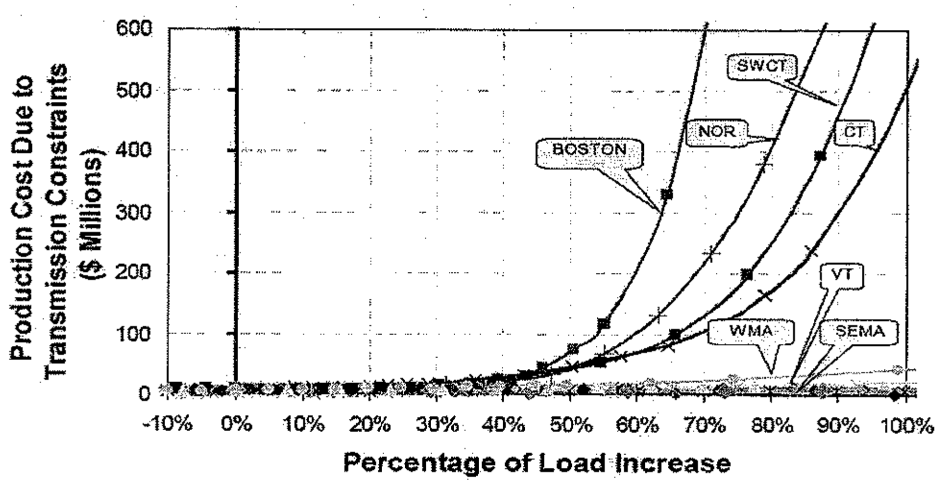
Power produced by DG units is supplied close to the load and thus reduces the amount of power that must flow into a region via transmission lines. This is especially important in areas subject to congestion. The price effect of even small reductions in transmission line power flow can be very large, as was found in a study made by Independent System Operator New England (ISO-NE) (ISO 2005):

C00382

"[The 2004 Regional Transmission Expansion Plan (RTEP04)] provides a range of market information .... It should be noted that there is a high degree of uncertainty associated with many of the assumptions. Future fuel prices, generation unit retirements, unit availability performance, bidding practices, demand growth, and other assumptions all could affect congestion costs and are all uncertain. RTEP04 therefore provides an indication of congestion-related trends, not projections of expected congestion costs."

ISO-NE conducted sensitivity analyses to identify the RTEP sub-areas having the greatest risk of creating higher costs due to transmission constraints. This is done by evaluating changes in system conditions in each sub-area (i.e., changes in generation and/or demand for electricity). Figure 3.6 shows that the Norwalk-Stamford, Southwest Connecticut, Connecticut and Boston sub-areas are more sensitive to these changes than the other sub-areas (ISO 2005)."

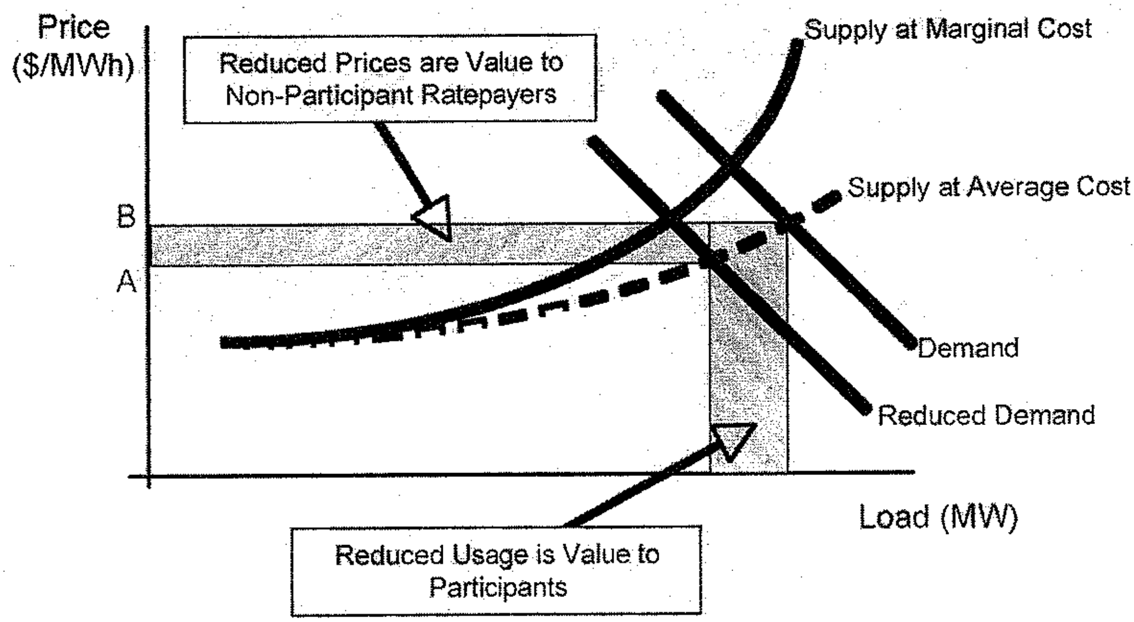
Figure 3-6. Production Costs and Sensitivity to Changes in System Conditions



3.4.2 Traditional Vertically-Integrated Markets

There are important distinctions between traditional vertically-integrated and the new organized markets when it comes to the economic impacts of reducing peak demand. Figure 3.4 shows the impacts in organized wholesale markets as every generator receives the marginal clearing price of power. But in traditional vertically-integrated markets, wholesale rates are set by the utility's power production costs plus a regulated rate of return, as shown in Figure 3.7. The economic benefit to all customers of reduced peak power requirements is therefore the reduction in the integrated average cost of power, as shown by the drop from point B to point A. Thus, compared to organized wholesale markets, the benefit of reduced peak power requirements is not as large. The utility in a vertically-integrated market experiences a reduction in operating costs but also loses the revenues associated with reduced generation.

Figure 3-7. Comparison of the Marginal Price to the Average Cost Seen by Customers at Regulated Utilities



3.5 Effects of Demand Reductions on Transmission and Distribution Equipment and Generating Plants

As discussed, reductions in peak demand by customers produce "upstream" reductions on local feeder systems, the transmission lines serving those feeders, and the generating plants serving those transmission lines. The extent to which demand reductions provide benefits to the system depends largely on the capacity of the existing equipment relative to existing and projected loads.

> **Feeder Capacity:**
> **It's Not a Fixed Value**
>
> *The maximum load limit on a feeder is a function of the individual limits on the various wires, transformers, switches, and other associated equipment. However, the load limit on electrical equipment is seldom a single number. For example, transformer ratings define normal and emergency limits for current levels and for voltage drops. Even an emergency limit can be exceeded for a given time period, although this can lead to thermal loss-of-life, which may in turn lead to equipment outages.*

While all electrical equipment has a nameplate rating for capacity, in practice this rating is seldom a fixed number. For example, the capacity of a combustion turbine is a function of the air temperature, pressure, and relative humidity, the heat content and pressure of the fuel service, and the time that has elapsed since the last turbine overhaul. Determining the capacity of a transformer is even more complex. As the load on a transformer increases, the temperature within the transformer also increases; and as the hours of operation at elevated temperatures increase, the transformer's lifetime and maintenance intervals are both shortened. Reflecting this cause and effect, an Institute of Electrical and Electronics Engineers (IEEE) transformer loading guide is based upon an exponential relationship between transformer life and its highest temperature (IEEE 1995; Hoff et al. 1996).

Transformers are therefore typically rated to operate for a limited number of hours per year above a given temperature. However, some utilities elect to deliberately exceed these load limits to meet system requirements and use proactive maintenance programs to counterbalance the extra wear and tear on the transformer (Woodcock 2004).

The capacity of the transmission system is an even more complex concept, because it changes term system conditions on a moment-by-moment basis and is dependent on the location of generation injections and demand withdrawals. Although we refer to transmission capacity, a more appropriate reference should be the transfer capability (i.e., the amount of power that a transmission feeder or a bundle of transmission facilities can transfer from one point (or region) to the other under predetermined system conditions). Most utilities specify transfer capability under pre-specified conditions such as using "N-1" reliability criteria. Thus, implicit in the transfer capability is a margin allowed for reliability. Additionally, some utilities make provision for two additional margins – transmission reliability margin (TRM) and capacity benefit margin (CBM). The remainder of the transfer capability of a specific transmission facility or a bundle of transmission facilities after netting out the applicable reliability margins is the transfer capability available for commercial energy transfers.

Therefore, when we consider the ability of DG to defer T&D and generating system capacity expansion, we are often taking aim at a moving target. However, operation of DG that reduces peak loads on a substation will always provide some benefit to that substation, whether by decreasing the required maintenance, increasing equipment lifetime, or actually deferring the installation of additional capacity.

3.6 Value of Offsets to Investments in Generation, Transmission, or Distribution Facilities

Utilities generally make investment decisions for generation and T&D capacity based on peak requirements. Thus, any reduction in peak power requirements provides direct benefits to the utility in the form of deferred capacity upgrade costs. This section of the report reviews multiple valuation methodologies in use. The Appendix provides a detailed example of how one of the methodologies can be applied.

3.6.1 Transmission and Distribution Deferral

A detailed review of available literature shows that of all economic benefits provided by DG, the ability to offset T&D investment is the most easily quantified and most often studied. This is understandable given the concrete and quantifiable nature of T&D investments. Two distinct approaches dominate the literature. The most detailed is a comparison of a site-specific cost of a proposed or existing DG project with specific avoidable distribution level upgrades. The second and more common approach compares the costs of generic DG proposals with average T&D expenses realized in response to historic demand growth. This second method is based on the assumption that:

"Avoided T&D costs for DG do not necessarily occur at the same time that DG capacity is added because often the T&D resources are already in place. However, in the long run, T&D resources must be maintained, replaced, and usually augmented to meet system growth. Therefore, in the long-term view, DG should contribute to a reduction in T&D expenses ... [especially]... from the perspective of a long-run equilibrium in which DG is planned and coordinated with a distribution system. ..... A key point is that DG has capacity value for a distribution system to the extent that it reduces the need for upstream capacity. Therefore, it makes sense to first calculate the potential value of DG as if it could be centrally dispatched. Then this potential value can be systematically exploited. Among other things, the distribution system can be designed or adapted to technically accommodate DG (Hadley et al. 2003)."

3.6.2 Capacity Basis for Value Calculations

Generally speaking, utilities typically make capital investment decisions in T&D capacity based on the cost per kW of "installed capacity" rather than cost per kW of "capacity shortfall." The use of installed capacity as a measure for lumpy T&D investments does not capture the often large amount of unused capacity in the near term.[26] In one example from DTE, a Detroit Energy company, $50,000 could be invested in a T&D system reinforcement project to permit a lumpy generation capacity addition of 2,500 kW. From a "capacity-added" perspective the T&D system reinforcement project costs $20/kW. However, not all the 2,500 kW is needed in the near term. The actual need is approximately 500 kW. Therefore from a capacity-shortfall perspective, the T&D system reinforcement projects costs $100/kW. DTE performed 35 such comparisons in 2003. While the costs ranged from $20 to $340/kW for the installed capacity, the costs ranged from $100 to almost $1100/kW on a capacity-shortfall basis. Therefore, from an investment perspective DTE makes the point that utilities should evaluate traditional T&D upgrade options from a capacity-shortfall point of view and compare their economics with alternatives such as DG. Such an approach is one way to deliver just-in-time and right-sized capacity to resolve smaller short falls while minimizing the initial capital outlay. This is especially applicable for problems that may only exist for a few hours per year or for capacity that may not be fully utilized for several years (Asgeirsson 2004).

A similar analysis has been made using actual costs at Southern California Edison (SCE) for multiple feeders with mixed residential, commercial, and light manufacturing loads:

"One way to determine the annual T&D cost to the utility, disregarding revenue growth, is to determine the annual carrying cost of a T&D expansion. SCE was able to provide historical cost data for recent upgrades similar to those that may be done on the Lincoln and Washington substations in California. Two 13,000 kW circuits were added to two separate substations at installed costs of $740,762 and $750,500, for an average installed cost of $57/kW. Assuming SCE's annual fixed charge rate is 12%, the average annualized carrying cost for each 13,000 kW upgrade would be $90,000/year. Assuming load growth of 1.3%...on a 13,000 kW circuit, the growth would be 170 kW for the first year. Because the minimum size of the circuit expansion,

$$\boxed{\text{Deferral cost} = \frac{\text{Avoided upgrade cost} \times \text{Fixed Charge Rate}}{\text{DG capacity required}}}$$

26 T&D capacity investments are called 'lumpy' because the installed size must be selected from available equipment sizes. Moreover, the labor and auxiliary equipment costs for any upgrade involve some minimum cost.

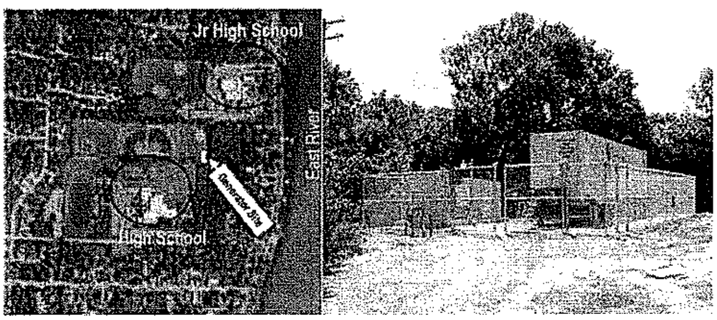
13 MW, is so much larger than the needed expansion, the first-year deferral cost would be \$530/kW per year for a 170 kW DG installation. Even if the expansion circuit relieves similar growth problems on an adjacent circuit, so that a DG capacity of 340 kW is needed, the annual deferral cost would still be \$260/kW for the first year. As this example shows, the annual deferral cost is a function of the avoided cost of the circuit upgrade, the fixed charge rate, and the size of DG that would meet the short-term needs of the circuit's growth (Kingston and Stovall 2006)."

3.6.3 Site-Specific Examples

The preceding section describes site-specific evaluations conducted for DTE and SCE. Resource Dynamics Corporation/Electric Power Research Group has also evaluated three site-specific options for utility-owned DG and found that DG is the most economical choice at one of the three sites (Resource Dynamics Corporation 2005).

In a separate study, the authors have analyzed T&D deferrals for an island off the coastal northeastern United States (Poore et al. 2002). Up to 7 MW of diesel generation were proposed, to be operated in response to power supply contingencies. The study authors describe the alternative "wires solution" as a wholesale replacement of the existing and outdated 23 kV system with an extension of the existing 69 kV transmission system and a pair of new 12.47 kV express feeders at a significant cost.

Figure 3-8. At DTE, a 1 MW Natural Gas Fired DG Unit was Installed on School Property to Defer a \$3.8 Million Substation Expansion Project for Five Years



Source: Asgeirsson

When the costs of these alternatives are compared on a Net Present Value (NPV) basis, the DG option is assessed to be economically attractive. Specifically, the study shows that the 7 MW diesel DG lease option will save approximately \$1 million on an NPV basis when all lease, fuel, and installation costs are considered. These savings may be even larger if revenues associated with selling energy into the power markets are considered (Poore et al. 2002).

3.6.4 Historic Transmission and Distribution Cost Deferral Examples

A recent examination of deferred T&D costs and long-run marginal costs from multiple perspectives in the SCE region have been made (Kingston and Stovall 2006).

The circuit peak loads, inflated by some contingency reserves factor, represent the capacity that the utility must provide at the substation and in the wires. As the load approaches this limit, the utility must usually invest capital to increase the circuit capacity to reliably meet consumers' demands. The cost of capacity additions tends to be location-specific and varies widely. Two recent studies used FERC Form 1 data to estimate the marginal cost of T&D. FERC accounts 360-368 contain distribution equipment that could be deferred or displaced by DG systems (FERC 2006; 18 CFR Sec. 141.1).

The first study, a part of the Regulatory Assistance Project (RAP) Distributed Resource Policy Series, examined the marginal T&D expansion costs for 124 utilities (Shirley 2001). This study found the national average cost between 1995 and 1999 was $590/peak kW for lines and circuits and $95/peak kW for transmission and substations. The standard deviation for each of these averages, $447/peak kW for lines and circuits and $91/peak kW for transmission and substations, indicates the broad range of the reported costs.

The RAP results are all based on the utility peak load, which tends to grow in a smooth and continuous manner. Capacity additions, on the other hand, tend to occur in discrete steps that correspond to available equipment sizes (e.g., rotating stock) or to capacity increments that justify the installation labor costs. For that reason, another study (Hadley et al. 2003) used the total installed kVA for distribution line transformers, rather than the system peak, to examine the marginal costs for 105 major utilities over the period from 1989 to 1998. The marginal distribution cost from that study (defined as the sum of both classifications from the RAP study, or $685/peak kW) was $239/kVA. To compare these two numbers, it is necessary to correct for power factor. If we assume that the power factor is 0.9, then the second study's value of $239/kVA would be $266/kW.

This is still not a direct comparison, however, because one value is based on system peak load and the other on installed capacity. These two values differ by a factor equal to the reserve margin, which varies from one location to another. For example, if the reserve margin is 15%, then a cost of $685/peak kW would be equal to a cost of $582/installed kW. The reserve margin also varies with time, being greatest **immediately following** a circuit upgrade, and being least **right before** a circuit upgrade.

A summary of these marginal T&D cost estimates is shown in Figure 3.9. The average, plus or minus one standard deviation, is shown for the RAP database after several outliers were removed. Even after excluding three very high-priced outliers, the data ranged from $127 to $3,085/peak kW (Shirley 2001).[27] In the DTE case, the utility's T&D average upgrade cost was $403/kW (Sheer 2003).

The Oak Ridge National Laboratory (ORNL) study conducted by Hadley et al. (2003) then goes one step further in calculating the T&D deferral value to the utility by considering the diversified coincident reliability of multiple DG units on a circuit, considering unit size, unit forced outage rate, and number of DG units. All too often, the contribution of a DG resource is disallowed because it is not 100 % reliable. It is more appropriate to treat it as one of many sources and loads and to consider the relationship between the desired reliability level, the forced outage rates of multiple DG units, and the relative location of the DG resources. Using this diversified coincident reliability, a capacity credit percentage is assigned to each element of the T&D investment expected to be located upstream of the DG location to determine the magnitude of costs offset by a typical DG installation.

Using a hypothetical feeder layout, this methodology suggests that a DG capacity credit of 60% could be applied to the distribution substation, land, and structures; and 20% to distribution poles, towers, and overhead conductors. No credit is given to distribution transformers, meters, street lights, etc because these facilities are assumed to be located downstream of the DG installation. For this hypothetical feeder,

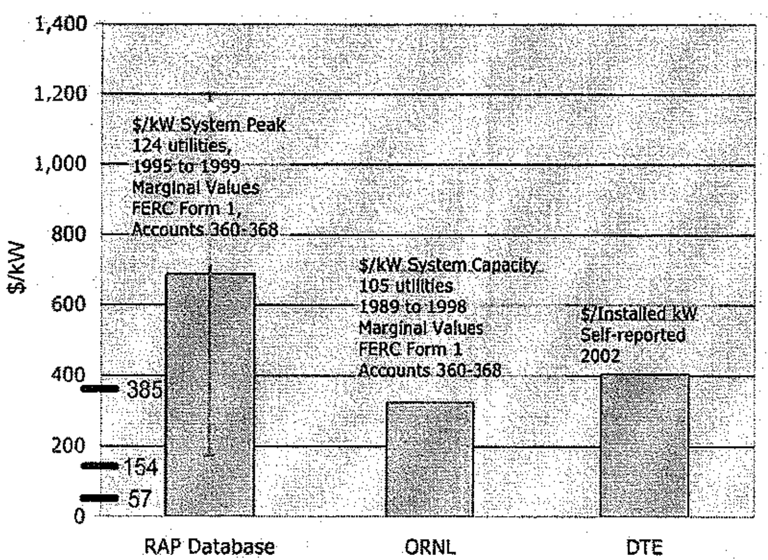
27 This data can also be viewed at http://www.raponline.org/Pubs/DRSeries/CostTabl.zip.

using 20 DG units with forced outage rates of 5%, the avoided capacity value of DG based on marginal costs was about one third of the total marginal costs for all T&D equipment (Hadley et al. 2003).

3.6.5 Deferral of Generation Investment

There is relatively less publicly available literature on generation deferral from DG development compared to T&D deferral. One reason for the lack of literature is that DG almost always costs more than a large centralized power plant on a cost-per-installed-MW basis due to the immense economies of scale surrounding construction and installation of power equipment. However, as discussed above, this may not be the case if DG installation is evaluated on a cost per MW "shortfall" basis. Thus, there can be economic benefits related to generation investment deferral that are directly attributable to DG.

Figure 3-9. Summary of Marginal Transmission and Distribution Cost Estimates



A study conducted by Hoff et al (1996) provided a technical evaluation of the use of DG as an alternative to large system capacity investments. The goal of this study was to:

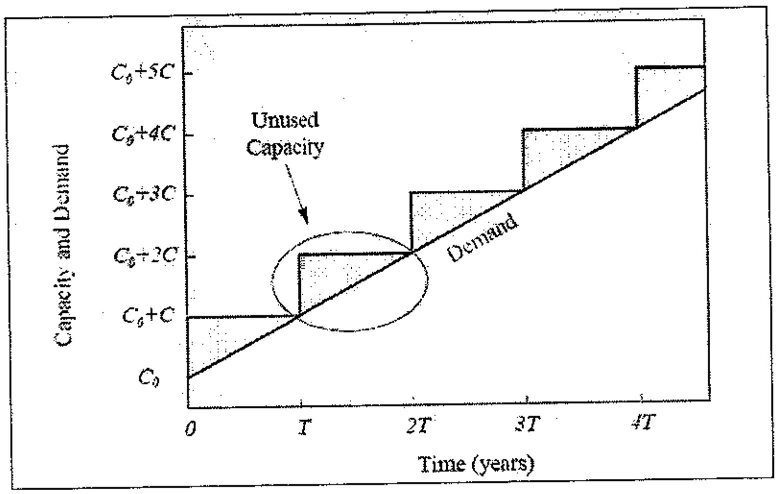
> "...present a simplified method to determine the value of deferring electric utility capacity investments using distributed generation. Consideration is given to both economic and technical factors, including uncertainty in the price of distributed generation. The technical evaluation is based on measured data from a 500 kW distributed generation photovoltaic (PV) plant in Kerman, California."

The study uses data from a specific 500 kW DG PV plant in Kerman, California, and suggests that the cost savings associated with deferring generating capacity investments can be accurately estimated using only seven economic parameters and a representative single day generation pattern. The study authors focus on the deferred generation investment available from DG. Specifically they focus on the "lumpiness" of generation and T&D additions, and the benefits that may be derived from adding DG in small increments to exactly match load growth as opposed to large single additions triggered at the first need for additional capacity. This allows investments to be more fully utilized rather than sit idle as demand grows to meet supply from centralized stations. Hoff et al (1996) describe the methodology and results of the single case study analyzed:

"Large investments have large capacities. In some cases, such as the generation system, capacity may be fully utilized immediately upon investment. In other cases, such as in parts of the transmission and distribution system, there may be unused capacity for a period of years."

This situation is illustrated by the darkened portions of Figure 3.10. The figure shows that an investment with a capacity of C is made every T years. Thus, there is excess system capacity immediately after the investment is made. Distributed generation capacity, in comparison, is installed frequently in very small sizes. This results in a situation in which capacity and demand are always equal. This eliminates the unused capacity portions of Figure 3.10. As presented in Figure 3.11, system capacity is slightly increased by adding distributed generation rather than reducing demand. More significantly, the capacity expansion plan is estimated rather than fully specified. Figure 3.11 presents the original (dashed line) and deferred (solid line) capacity expansion plans. The markings on the axis correspond to the timing and capacity of the deferred plan. The difference between the two plans is that, at time equal to 0, a small amount of distributed generation is installed. This increases the capacity of the system by C_{DG} and defers the original plan by T_{DG} years (Hoff et al. 2006).

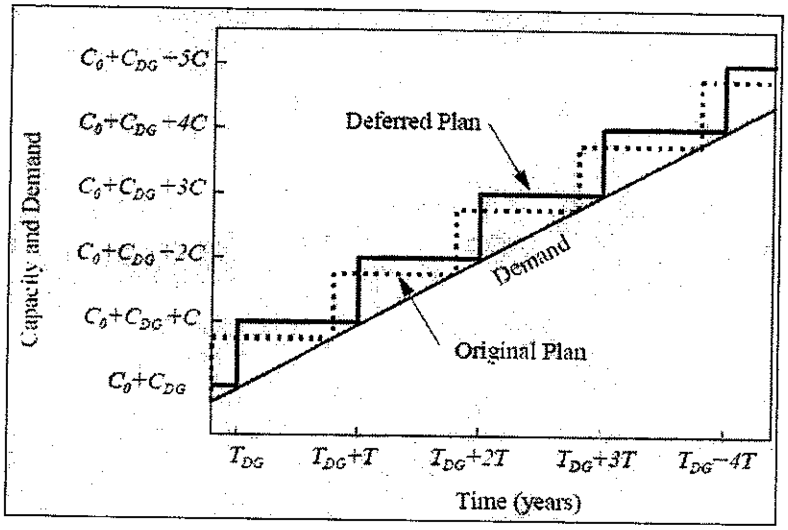
Figure 3-10. Distributed Generation Can Reduce Unused Capacity[28]



28 Excerpted from Hoff, T. E., Wenger, H. J. and B. K. Farmer, 1996, "Distributed Generation: An Alternative to Electric Utility Investments in System Capacity" Energy Policy 24(2): 137-147. Original designation was Figure 4.

000386

Figure 3-11. Break-Even Price is Calculated by Altering the Original Capacity Expansion Plan



The study provides further detail through the addition of uncertainty, option value, changes in system losses, and DG cost reductions to the simple approach noted above. Generally, modular-sized DG systems offer utilities the flexibility to reduce installed capacity risk from unused capacity. The economics of centralized utility power plants tend to be "lumpy," and many of these investments are sized beyond their near term capacity needs. For a utility in a deregulated market, such unused capacity reflects a direct cost to the utility. For those utilities in regulated markets, a case would have to be made before regulators through a prudence review process to rate base the investment. If DG resources are deployed where applicable, it can minimize utility exposure to large unused capacity. Additionally, demand uncertainty from demand growth and demand shifts can be large in some regions, and deployment of DG can help mitigate such risks.

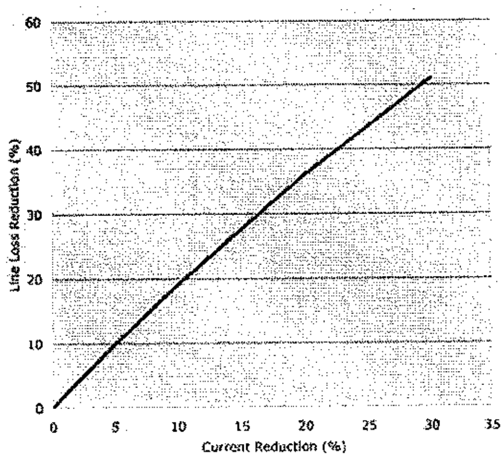
The study does provide some quantification of benefits specific to the Kerman PV facility, but the key conclusion is that this study proves you can quantify benefits with only a few (seven) data points, and DG output for a sample day.

3.7 Line Loss Reductions: Real and Reactive

When electrical current flows through a wire, some of that energy is lost in the form of heat. (Approximately 5% to 8% of the energy produced by power plants is lost before it reaches the customer [EIA 2004].[29]) This is especially important at peak load times, when the greater current flow generates greater heat and the wire temperature (which is also affected by air temperature and wind speed) reaches its greatest value.

Transmission Line Losses are Reduced by Distributed Generation

Line losses are proportional to the electrical resistance of the wires and to the square of the current flowing through the wires. Reducing the current by 10% reduces the losses by 19%.



The total current flow in a conductor is the sum of the current flows associated with the real and reactive power components (see Definitions and Terms for a definition of real and reactive power). Reducing either the real or reactive power flow on a transmission line will therefore reduce the losses associated with that current. Reducing the current requires decreasing the load, real and/or reactive, or serving some of the load locally with a DG system. Line losses occur not only in the wires, or conductors, but also in transformers and other transmission and distribution system devices.

Real and reactive line loss reductions attributable to DG installations have been both measured and simulated. In every case, the loss reductions are location specific. The extent to which energy losses are reduced depends on the relative location of the central generating stations and the load and on the equipment components and characteristics that operate between the two. The energy losses are also a function of the other demands on the system, because a more heavily-loaded system will run at a higher temperature, which in turn increases the system resistance and increases the total energy losses. Note that DG reduces line losses whenever it operates, but the line loss savings are greatest at those times when the system is most heavily loaded.

3.7.1 Measured Reductions in Line Losses

At one location, reductions in energy losses due to an actual DG installation were carefully measured.

> "Four sets of loss savings tests were performed on July 22, 1993 and August 24, 1993. The tests were performed by turning the [DG] plant on and off and measuring the load (kW) at the substation with PV plant on-line and off-line. Loss savings is the difference between load with PV off-line and the sum of load with PV on-line and PV output. ... Plant output during the tests ranged from 0.39 MW to 0.45 MW with an average of 0.40 MW. ... Results indicated that the 0.50 MW Kerman PV plant has system wide (feeder, transformer, and transmission system)

[29] This information was derived from Table 7.2, Table 1.1, and Table 6.3 from the Energy Information Administration website data for net generation, net imports, and direct customer use of electricity from 1993 to 2004, which is available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.

energy loss savings equal to 6% of the plant's energy output.... Peak load loss savings at the transformer equal 5% of its capacity...These results are site specific (Hoff and Shugar 1995)."

3.7.2 Simulated Reductions in Line Losses

A detailed grid analysis was made for the radial Silicon Valley Power (SVP) system, a municipal network of 850 buses serving the city of Santa Clara, California. Both the transmission and distribution system components were included in the study, using measured historical load data from an existing SCADA system at the feeder bus level. Based on that model and information regarding individual customer peak loads, many possible DG installations were evaluated, resulting in a selection of projects that optimized the network performance.

Proprietary software analysis, optimization, and ranking of the SVP system identified "a large, diverse population" of several hundred valuable power projects that were worthy of undertaking. The software manufacturer suggested its changes could achieve an impressive 31% reduction in real power losses and a 30% reduction in reactive power consumption (Engle 2006). Losses were reduced at three times the system's average loss rate by adding properly located small generators. The optimal locations were generally near the ends of main feeders, where adding DG benefits the feeder and the entire system. Generally speaking, the more remote the DG positioning, the greater the grid benefit. The authors of that study summarized their results as:

> "We showed that the reduction in real power losses within the SVP system was due to an increase in network efficiency, and not purely due to a reduction in the load being served through the network. There are significant loss reductions in the surrounding regional transmission system as well...these projects also eliminate low- and high- voltage buses, they improve network voltage profiles, and they reduce the amount of real power stress in the system. Importantly...these benefits are not limited to peak load conditions. In some cases there are greater benefits under conditions other than the Summer Peak...the Optimal DER Portfolio projects have the potential to yield network benefits in the same range as those of transmission-level system upgrades using these same measures (Evans 2005)."

3.8 Major Findings and Conclusions

Installation and use of DG systems by customers and/or utilities can produce reductions in peak load electricity requirements, depending on how the DG is operated. Because most investment decisions for new plant and equipment in the electric power industry are driven by peak load requirements, reductions in peak load can displace or defer capital investments. In addition, reductions in peak load, particularly during critical peak periods which typically occur during excessively hot weather, can reduce the costs of electricity because it is usually the case, in both organized wholesale markets, and traditional vertically integrated markets, that the most expensive power plants to operate are the last ones to be dispatched from the "resource stack." Peak load reductions can eliminate or reduce the need for power from these most expensive power plants. Finally, reductions in peak load can reduce "wear and tear" on electric delivery equipment, thus reducing maintenance costs, extending equipment life, and reducing overall capital investment requirements.

Section 4. Potential Benefits of DG from Ancillary Services

4.1 Summary and Overview

FERC has defined ancillary services as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." There are several categories of ancillary service, including voltage support, regulation, operating reserve, and backup supply.[30]

Voltage support relates to the ancillary service of ensuring that the line voltage is maintained within an acceptable range of its nominal value. Line voltage is strongly influenced by the power factor of the particular line (i.e., the amount of real and reactive power present in a power line). In turn, the power factor can be modified by the installation, removal, or adjustment of reactive power sources. Reactive power can be obtained from several sources, including electric generators, electronic waveform generators (i.e., power electronics), shunt capacitors, static volt-ampere reactive (VAR) compensators, synchronous condensers, or even from lightly loaded transmission lines.[31]

Regulation deals with the minute-to-minute imbalances between system load and supply. Generation that provides regulation service must be equipped with automatic control systems capable of adjusting output many times per hour and must be on-line, providing power to the grid.

Operating reserve comes in two categories—spinning and non-spinning. *Spinning reserve* comes from generating equipment that is on-line and synchronized to the grid, that can begin to increase output immediately, and that can be fully available within 10 minutes. *Non-spinning reserve* does not have to be on-line when initially called, but is typically is required to fully respond within 10 minutes of the call to perform.

Backup supply services and *supplemental reserves* are very similar in function, differing in response time requirements. The response time requirements for backup supply vary across transmission control areas but are generally in the 30- to 60-minute time frame. Because supplemental reserve and backup supply do not require a generation source to be already on-line when called, distributed generation (DG) may be more likely to participate in these two ancillary service markets.

Black-start service is the procedure by which a generating unit self-starts without an external source of electricity thereby restoring power to the Independent System Operator (ISO) Controlled Grid following system or local area blackouts.

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30 The services listed below are not all FERC-defined ancillary services.

31 Schedule 2 of the FERC *pro forma* OATT considers reactive power obtained from generation sources as an ancillary service. However, provision of reactive power from transmission components (power electronics, capacitors, synchronous condensers) is not considered an ancillary service in the *pro forma* OATT. Costs associated with reactive capability provided by such transmission components are recovered through charges for standard transmission service, as opposed to *pro forma* OATT-defined ancillary services.

While not often used for the purpose of providing ancillary services, DG has the capability of providing local voltage support and back-up or supplemental reserves, if the units are located on those portions of the grid where these ancillary services are needed, and if they are under the control of gird operators so that they can be called upon during times of system need.

4.2 Potential Benefits of the Provision of Reactive Power or VAR (i.e., Voltage Support)[32]

The efficiency of the transmission and distribution (T&D) network improves significantly when reactive power production from central station facilities is replaced by demand-side dynamic reactive power resources. Because sending reactive power to loads from central station facilities "takes up space" on transmission lines, providing reactive power locally frees up useful T&D system capacity for additional real power transfers from generation sources to loads. In addition, providing reactive power locally reduces real and reactive power losses, improving the efficiency of the T&D system.

Reactive power supply sources are broadly categorized as either dynamic or static. Dynamic reactive power resources include generators and dynamic VAR systems. Static reactive power resources include synchronous condensers, static VAR compensators, and capacitor banks. Dynamic sources such as generators are preferable to static sources mainly because their output responds dynamically to changing reactive power demand conditions. In contrast, static sources are incapable of rapidly responding to changing reactive power demand conditions. Thus, while static sources can provide reactive power service under normal operating conditions, under contingency conditions such as a transmission facility outage and/or a generation unit outage, static sources are more likely to fail when needed most. [33]

Under such contingency conditions, dynamic reactive power resources can rapidly respond to changing reactive power needs to maintain reliability. Thus, central station generators are a prime source of dynamic reactive power and are economically valuable in supporting the T&D system and thereby maintaining system reliability.

However, using DG to provide for reactive power can save distribution line losses as well as transmission line losses. For example, according to Kueck et al. (2004):

> "Distribution losses are the largest percentage of total system losses, comprising about 27% of total losses. When reactive power is supplied from a Distributed Energy Resource (DER) such as a microturbine, losses on the distribution feeder can be reduced or even eliminated. Local power quality can also be significantly improved."

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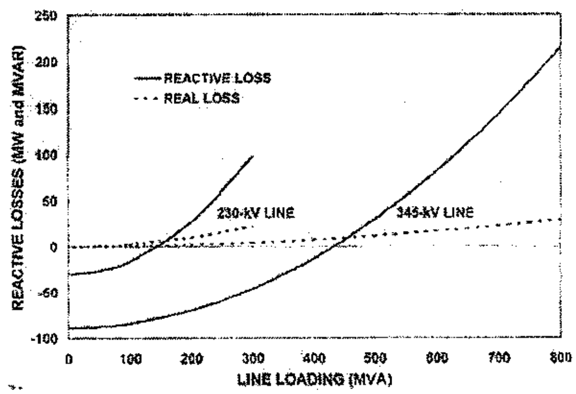
32 Electricity travels in a wave-form on an electrical conductor. There are two waves that flow in the conductor, the current and the voltage. The degree to which these two waves are non-coincident (called the phase angle) determines how much of the electricity is available to do useful work (called **real power**) and how much is available to sustain the voltage level (called **reactive power**). The wave also has a frequency expressed in cycles per second, or Hertz. Both the voltage and the frequency must be controlled within very tight limits to effectively serve customer needs and avoid damage to equipment.

33 Capacitors, a static reactive power source, are used heavily to provide reactive power on the distribution system because they are simple and inexpensive, but they have significant draw-backs. One author has noted that transient over-voltages caused by capacitor switching can be magnified within customer facilities, cause adjustable speed motor drives to mis-operate, and affect the operation of a wide variety of electronic equipment. (Electric Power Research Institute 2003.) Reliance on capacitor banks can also increase a system's risk of voltage collapse. Capacitor-provided power factor compensation can permit a transmission line to carry a heavier load, but the total load will be more susceptible to failure. That is, the line will suffer a complete voltage collapse after a smaller voltage drop with capacitors than it would without capacitor compensation. Indeed the shape of the voltage collapse curve becomes sharper and the vulnerability grows as the amount of capacitors increases.

Figure 4.1 shows the complex behavior of transmission lines with respect to reactive power. When the amount of power being transferred across a transmission line is low, the transmission line actually generates reactive power. On the other hand, at loading levels near the rated capacity of the transmission line, the transmission line consumes a significant amount of reactive power (several times the amount of the real power losses in the transmission line). At these times of heavy transmission loading, a significant amount of reactive power is required from generation or other transmission sources simply to supply the transmission lines with the reactive power they require to maintain system voltages. Attempts to send additional reactive power to loads at these times are ineffective, since the additional reactive power transmitted increases the total load on the line, which in turn increases the amount of reactive losses in the line. Given this complex behavior of the transmission system, providing reactive power locally through the use of DG (or other means), when possible, allows system operators to avoid sending reactive power over heavily loaded transmission lines and incurring these avoidable reactive losses.

The location of dynamic reactive power resources is also very important and this is another reason why DG units that are designed and operated to produce or absorb reactive power can be even more economically valuable to the electric system. Unlike real power which can be economically transmitted from remote central station generating resources over long distances to demand locations, there are often significant transmission losses in transmitting reactive power from central station generating resources to demand locations.

Figure 4-1. Line Loading and Reactive Power Losses



Therefore, under both normal and contingency conditions, it is good utility practice to have these dynamic reactive power resources distributed throughout a grid operator's footprint and closely located to load to ensure that local reactive power resources are available close to potential demand locations – hence the significance of the economic value of reactive power from DG.

4.3 Simulated Distributed Generation Reactive Power Effects

Reactive power analysis has been completed using a variety of grid simulation tools and there are conflicting assessments of the ability of DG to reduce the system reactive power requirements.

Two studies that include detailed grid analysis for strategic locations illustrate significant reactive power savings associated with DG. The first of these studies estimates that a 500 kW DG installation would save losses in the following amounts: 114 kVAR on the distribution system, 113 kVAR on the transformer, and 225 kVAR on the transmission line. The second study examines specific feeders in Silicon Valley; results show that siting DG reactive sources close to the load in these geographic areas could reduce overall reactive power consumption by about 30% (Evans 2005).

It's important to note that both synchronous machines and those with power electronics can provide reactive power even when they are "off"; that is, when they are not producing real power.

If there were a clutch or eddy current drive between the generator and the driver (a reciprocating engine, a turbine, etc.), the generator could be operated in synchronism with the grid and the engine left in a standstill condition. The generator exciter could then be controlled to supply or absorb reactive power in response to the local voltage. However, small generators used for backup or auxiliary power are often not equipped with exciters that allow control of reactive power output. In these cases, a multilevel converter (MLC) could be used at the output of the generator to supply the reactive power. With an MLC, the generator could be turned off and the MLC used to supply reactive power to the distribution system as controlled by a voltage setpoint. The generator would need to be on, obviously, to supply real power. (Hudson et al. 2001.)

One analyst calculated the voltage support available along a feeder line as a function of the DG location. That detailed circuit analysis demonstrated that the voltage support at any particular feeder location is the product of the DG plant current and the conductor impedance between the transformer and the point at which the lateral is attached to the line between the transformer and the DG. This shows that voltage support is independent of the total feeder current and is linearly related to DG plant output (Hoff et al. 1994).

Another study modeled, for the purpose of formulating network design criteria, the interaction of multiple voltage support DG units. The results from that model show that the impact of voltage support DG increases with the increase of size and/or number of voltage support DG units. Based on those results, the analyst was able to propose a design scheme for a voltage support DG controller based on voltage sensitivity that would correct the network voltage effectively (Kashem and Ledwich 2005).

These studies clearly show that in some locations DG can improve the efficiency of the system such that significantly less reactive power is needed. However, not all analysts agree. Another study that evaluated the impact of DG on reactive power requirements for California stated, "Reactive power requirements for voltage support might be reduced with lower system peak loads. However, this effect would be extremely difficult to estimate and is likely to be small." (Energy and Environmental Economics, Inc. 2004.)

4.4 Spinning Reserve, Supplemental Reserve, and Black Start

Distributed generation has not traditionally been considered as an attractive candidate for ancillary services. To explore DG potential contributions in this area, an in-depth examination of the ability of DG to provide other ancillary services was completed (Hudson et al. 2001):

> "Spinning reserve is a relatively high-priced service and may be an excellent candidate for DG. This is an especially good prospect for types of generation that can be operated in an idle mode or even shut down and then brought up to full load quickly.
>
> ... Some of the new microturbines can be started and ramped up very quickly, in a matter of seconds. If these microturbines were aggregated into meaningful generation blocks of 1 MW or more, they could be ideal sources for spinning reserve. One benefit of using small quickstart generating units is that there is no environmental impact from the units idling on-line.

Smaller distributed generators may be designed to provide rapid, large power changes in response to frequency changes to help preserve system stability. While provision of spinning reserve would be a new concept for DG, it is likely to be put into effect in the future if DG constitutes a significant percentage of the total generation —i.e., when larger DG aggregations are capable of providing a few hundred megawatts of power. Distributed generators can provide this service relatively easily because the control signal (system frequency) is already available at each distributed generator. In the long term, DG may be used with power electronics to dampen and correct frequency oscillations … [and regulate voltage] ….

The only distributed generators that are likely to be used for black start are larger units with capacities in the tens of megawatts that are already designed for blackout service. There are a large number of such units, at hospitals, airports, and other large installations; and they may be good candidates for black-start service."

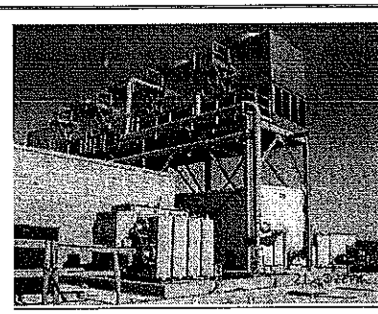
Generation assets that provide *regulation* must be on-line, providing power to the grid. Customer-owned DG is unlikely to provide this ancillary service because: (1) in most locations, the distributed generator is prohibited from providing power to the grid, and (2) the distributed generator operation would have to be controlled to meet the grid power needs rather than the customer's thermal or electric loads. However, regulation services could easily be provided by a utility-owned and operated DG resource.

4.5 Basis for Ancillary Services Valuations

Valuation methodologies for ancillary services are not new. In the 1990s, when the restructuring of electric power markets and regulations was being addressed across the country, a number of studies were made to determine the appropriate market basis for services that had previously been bundled within the traditional model for vertically integrated utilities.

Studies of the costs of ancillary service provision from fossil fuel plants include Curtice (1997), El-Keib and Ma (1997), Hirst and Kirby (1997a), (1997b), and Hirst (2000). Hirst and Kirby (1997b) actually run a simulation of the market for energy and ancillary services for a fossil fuel mix and Hirst (2000) study the operation decisions and profits of a fossil fuel plant operating in markets for energy and ancillary services (Perekhodstev 2004).

Table 4.1. Distributed Generation Can Provide Black-Start Services

<u>**Dell Children's Medical Center of Central Texas**</u> A DG system is an integral part of a new children's hospital in a brownfield development at the site of Austin's former Robert Mueller Municipal Airport site. The DG system has been designed to provide electricity, hot water, chilled water, and black-start capabilities to the hospital and to future tenants in the development.	

000390

The Powell Valley Electric Cooperative

This cooperative, which serves eight rural counties in an area about 120 miles wide along the border of Tennessee and Virginia, installed 22 MW of DG in 2000. The DG units are available to provide contracted peaking power, to serve a critical needs circuit in Powell Valley in case of a grid power failure outside their system, and to provide black-start power to a 700 MW fossil-fueled power plant located about 20 miles away. This 700 MW power plant is also the main source of power to Powell Valley, and running DG reduces the load on the connecting transmission line by 20 MW.

Source: Hadley et al. 2006.

Regulation and spinning reserves require generating units that are already on-line and synchronized to the grid, but that are operating at less than their maximum capacity. They therefore incur the following costs (Perekhodstev 2004):

Opportunity and re-dispatch cost. If the generator's marginal cost is lower than the market price, the generator would earn profits operating at full capacity. Therefore, reduction in the energy output necessary to provide regulation is associated with the opportunity cost of foregone profits, roughly proportional to the difference between price and marginal cost of generation. If generator's marginal cost is higher than the energy market price, the re-dispatch cost of regulation is proportional to the difference between marginal cost and price.

Efficiency penalty. In order to be able to ramp up quickly, a generator providing regulation or spinning reserve may have to operate at reduced efficiency. This "efficiency penalty" is especially pronounced for steam units.

Energy cost. Regulation may require a generator to perform fast ramp-ups and ramp-downs. Thus, units offering regulation may incur energy costs associated with turbine acceleration and deceleration.

Wear-and-tear costs. For regulation, frequent output adjustments may incur additional wear-and-tear costs.

The manner in which these costs are reflected by the market is described by Hudson et al. (2001):

> "The revenue obtained from participating in competitive energy and/or ancillary service markets will vary, depending on many factors, including the season, the time of day, the weather, and the applicable market settlement rule. In most competitive energy markets, every winning (selected) bidder is paid the last accepted bid price (i.e., the marginal price). Thus, unless a bid is equal to or greater than the marginal price, the revenue received will be at a rate greater than the actual price bid. This is termed a uniform price auction and is a commonly used settlement method in the energy market. Settlement rules for ancillary services are more complicated and have considerable variation among control areas. One settlement arrangement for ancillary services is to pay all successful bidders the last accepted bid price for a service plus an opportunity cost payment for the profit forgone in the energy market. (A generator cannot provide both firm energy and ancillary service support simultaneously and therefore must forgo participation in the firm energy market to the extent of its ancillary service bid.)"

In the California market, the portion of ancillary services that encompasses reserves and regulation capacity ranges between 1% and 5% of the total energy cost, with an average of 2.84% (Energy and Environmental Economics, Inc. 2004). In an analysis of the Pennsylvania/New Jersey/Maryland Interconnection (PJM) region, the portion of the ancillary services that encompasses reserves was estimated to range between 0.2% and 2% of the total energy costs, with an average of 0.5% (Hadley et al. 2003).

A detailed distribution feeder model was used to evaluate the impact of one particular DG installation. The analysis started with the reduced load on the distribution system, determined the loss savings through the transformer based on generation and feeder loss savings, and finally added the transmission loss savings. At that location, the analysis found that the kVAR savings were equal to 90% of the DG unit's kW rating, and were worth $41/kVAR in 1990 (Shugar 1990).

4.5.1 Market Value

4.5.1.1 Reserves

The benefits of DG to a utility from the provision of ancillary services other than voltage support come from savings in reduced levels of operating reserves from utility generation facilities and potential reductions in transmission reliability margins (TRM) and capacity benefit margins (CBM), especially for feeders that have connected DG facilities. Thus, any reduction in TRM and CBM could enable additional transfer capability on the transmission system for commercial energy transfers, which could provide direct benefits to the utility and to customers of the utility. For T&D systems close to their reliability threshold, any reductions in TRM and CBM will provide immediate relief and potentially defer immediate needs for T&D upgrades.

Many markets have established market-based or cost-based rates for these services. For example, in New York generation owners bid to provide operating reserves and regulation services. Similarly, in New England these services are market-based and consumers ultimately pay for the cost through rates. The average prices for the last six years for regulation and spinning reserves for the three northeast markets is summarized in Table 4.2.

For the regulated markets, there are no established procedures for the provision of, or the payment for, these services by non-utility generating resources. However there exist sufficient historical market data to permit an estimation of the economic benefit of DG in providing these ancillary services.

Table 4.2. Historical Annual Average Regulation and Ten Minute Spinning Reserve (TMSR) Prices in NYISO, PJM and ISO-NE (Nominal $/MWh) (Source: PJM, NYISO and ISO-NE)

Year	NYISO		ISO-NE		PJM	
	Regulation	TMSR	Regulation	TMSR	Regulation	TMSR
2000	14.9	19.6	4.2	1.4	NA	NA
2001	3.8	7.3	5.2	0.8	NA	NA
2002	1.1	1.3	5.4	2.0	NA	5.2
2003	3.0	1.3	5.3	2.4	NA	8.3
2004	2.4	1.4	NA	NA	NA	7.4
2005	21.0	21.5	NA	NA	64.0	3.5

The Hadley et al. (2003) study developed an approach for assessing economic benefits to utilities and society as a whole from the participation of DG in the provision of ancillary services other than VAR support.

4.5.1.2 Reactive Power

As noted by Li et al. (2006):

> "Evaluating the economics of reactive power compensation is complex. There are no standard models or analysis tools. There are no fully functioning markets for reactive power in the United States, so data on costs and benefits is difficult to find. It is an emerging area of analysis that is just beginning to attract attention of researchers and analysts. This is not surprising, given that the revenue flow associated with reactive power is less than 1% of the total U.S. electricity market. However, the importance of reactive power as a component of a reliable power grid is not measured by its market share of power system sales. The role of reactive power in maintaining system reliability, especially during unforeseen system contingencies, is the reason for the growing interest by regulators and system operators alike in alternative reactive power supplies.
>
> Institutional arrangements for obtaining reactive power supplies include: (i) pay nothing to generators, but require that each generator be obliged to provide reactive power as a condition of grid connection; (ii) include within a generator's installed capacity obligation an additional requirement to provide reactive power, with the generator's compensation included in its capacity payment; (iii) pay nothing to generators (or include their reactive power obligations as part of their general capacity obligation), but compensate transmission owners and load serving entities for the revenue requirements of transmission-based solutions; (iv) determine prices and quantities for both generator-provided and transmission-based solutions through a market-based approach such as a periodic auction (for reactive power capability) or an ongoing spot market (for short-term reactive power delivery); and (v) centrally procure (likely on a zonal basis) reactive power capability and/or supplies according to a cost-based payment schedule set in advance.
>
> Currently there are no distributed generation devices receiving compensation for providing reactive power supply. However, some small generators have been tested and have the capability to be dispatched as a source of reactive power supply. There are also some instances, typically in urban centers where there is an imbalance between loads and reactive power supplies, where distributed generation based reactive service show competitive payback periods compared to other technologies." (Li et al. 2006.)

Installed reactive power capacity is treated differently in each power market in the United States. In those regions served by organized wholesale markets, cost-based approaches have been established and used to set prices for reactive power and voltage support ancillary service.

Traditional Vertically Integrated Markets

In vertically integrated markets, some generation resources are paid for reactive power services, while others are not. Those resources that receive payments are usually reimbursed their annual reactive power revenue requirement. This revenue requirement is derived using the American Electric Power (AEP)

Methodology,[34] which seeks to ensure recovery of only the investment costs associated with the installed reactive power producing facilities.

Organized Wholesale Power Markets

PJM

Black-start service is remunerated based on the revenue requirement of the unit. The revenue requirement comprises a fixed (capacity) component and a variable component. The variable component covers operation and maintenance (O&M), training, fuel, and carrying costs required to support the service.

NYISO

Payments to generators that supply black start capability cover the following costs:

- Capital and fixed operation and maintenance costs associated with only that equipment which provides Black Start and System Restoration Services capability
- Annual costs associated with training operators in Black Start and System Restoration Services
- Annual costs associated with Black Start and System Restoration Services testing in accordance with the ISO Plan or the plan of an individual Transmission Owner.

NYISO has a separate payment schedule for existing generators (new generators are excluded) in the Consolidated Edison Transmission District. These receive annual compensation for providing black start and system restoration services based on unit type and the level of their interconnection to the New York State Transmission System as shown in Table 4.3.

Table 4.3. Compensation for Services Based on Unit Type

	Steam Turbine	Gas Turbine
345 kV	$350,000/yr/unit	$350,000/yr/site
138 kV	$300,000/yr/unit	$300,000/yr/site

ISO-NE

Generators providing black-start capability are paid a fixed monthly compensation based on the capability of the unit. It is calculated as follows:

$$C_i = \frac{Y}{12} \times (\text{Claimed Capability for that Month})$$

Where C_i is the monthly compensation and Y = $4.50/kW-year for calendar year 2006

[34] AEP Methodology is derived from American Electric Power Service Corp., Opinion No. 440, 88 FERC 61141 (1999).

New York Independent System Operator (NYISO)

For example in NYISO, payment for generators and synchronous condensers eligible for Voltage Support Service and under contract to supply Installed Capacity are based upon two major components: (1) fixed monthly payments to all eligible suppliers providing Voltage Support Service based on the embedded cost of reactive power facilities, and (2) lost opportunity cost payments for Suppliers providing Voltage Support Service in the event that the NYISO dispatches or directs the generator to reduce its real power (active power) output in order to allow the unit to produce or absorb more reactive power. For suppliers that are not under contract to supply Installed Capacity, the fixed monthly component is pro-rated by the number of hours that the resource operated in the month.

NYISO's embedded cost calculation methodology incorporates (1) the annual fixed charge rate associated with the resource capital investment, (2) current capital investment of the resource allocated for supplying Voltage Support Service, and (3) operation and maintenance expenses for supervision and engineering allocated for supplying Voltage Support Service.

Independent System Operator New England (ISO-NE)

ISO-NE compensates generators that provide reactive power based on four components:

- Capacity costs. This is the fixed capital costs associated with the installation and maintenance of the capability to provide VARs. Any generator that is in the market and provides measurable voltage support as determined by ISO-NE is considered a Qualified Generator.
- Lost Opportunity Cost. This is the value of the lost opportunity cost (in the energy market) of generators that are required by the ISO to reduce their reactive power output in order to provide reactive supply and voltage support.
- Cost of Energy Consumed. This is the cost of energy used by reactive power sources to provide VAR support. Under the current tariff, ISO-NE pays the cost of energy to hydro and pumped storage units that are motoring to provide reactive power at the request of the ISO. For synchronous condensers and static controlled VAR regulators, this cost is treated as losses on the system.
- Cost of Energy Produced. This is the portion of the amount paid to Market Participants for energy produced by a generating unit that is considered to be paid for VAR support under Schedule 2[35].

Pennsylvania/New Jersey/Maryland Interconnection (PJM)

In PJM, each Generation Owner is paid an amount equal to the Generation Owner's monthly revenue requirement as accepted or approved by FERC. If PJM requests a generator to reduce its real power output in order to produce reactive power, PJM also makes a lost opportunity cost payment that represents the value of the generator's lost opportunity cost in the energy market. Generating units designated as Behind the Meter Generation such as some DG resources are not eligible for these payments.

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35 ISO-NE Open Access Transmission Tariff

Midwest Independent Transmission System Owner (MISO)

In MISO, rates for VAR services are zonal, based on the annual revenue requirement of Qualified Generation units that provide the service. Each Qualified Generator owner is paid a pro rata allocation of the zonal revenue collected under Schedule 236 based upon the Qualified Generator's respective share of the relative rates within the pricing zone (i.e., rates of the Qualified Generator divided by the total rates of Qualified Generators in its zone).

Electric Reliability Council of Texas (ERCOT)

In ERCOT generation resources (including self-serve generating units) that have a gross generating unit rating (single unit or aggregated at a single transmission bus) greater than twenty MVA are required to provide Voltage Support Service in ERCOT. Such generators must be capable of producing a reactive power within the range of power factors of 0.95 leading or lagging at the rated capability of the generation resource. Qualified renewable generation resources in operation before February 17, 2004, and all other generation resources that were in operation prior to September 1, 1999 are held to lower requirements. ERCOT provides no compensation to generation units for the provision of voltage support within the required range. However, units required by ERCOT to reduce real power in order to provide voltage support are compensated as part of the Out-Of-Merit-Energy (OOME) down payment.

California Independent System Operator (CAISO)

In CAISO, Generators in the CAISO market are required to provide voltage support by operating within a band of 0.90 lagging and 0.95 leading power factors. (Generators that are unable to meet the requirement can apply for an exemption.) Generators receive no compensation for operating within the specified range although the ISO may give them time-varying instructions to operate within the specified range.) If necessary, CAISO may select generators to provide reactive power outside the specified range. Such generators will be paid the opportunity cost of reducing energy output to produce reactive power. The opportunity cost is calculated as the product of the energy reduction and the difference between the Zonal Ex Post Price and the generators bid price, if greater than zero.

United Kingdom Ancillary Services Market (including Provision of Reactive Power)

Specific examples of the quantifiable economic benefits associated with DG and provision of VAR support are few and far between. This is largely due to the fact that relatively small amount of benefits are realized in most generic applications. One study which does highlight the VAR benefits of DG was prepared by Ilex Energy Consulting of the United Kingdom. The stated purpose of this study is outlined in the report (Ilex Energy Consulting 2004):

The aims and objectives of the study were to investigate the potential for creating ancillary service markets at the distribution level in Great Britain. Specifically the study sought to:

- Investigate any existing arrangements for distribution level Ancillary Service markets worldwide.
- Review the high-level options for the design of ancillary service markets and identify any regulatory and legislative changes that might be required.

36 MISO Open Access Transmission Tariff

- Examine the prospects and opportunities for the different forms of distributed generation and assess whether the creation of different services would incentivise generation to connect to the distribution network.
- Investigate the commercial framework and technical procedures that might be required.
- Explore the infrastructure requirements.
- Assess the impact on different market participants.

The scope of the project included a consideration of the opportunities for DG to contribute to existing Transmission System Operator (TSO) ancillary services and an investigation of the potential for DG to contribute to new Distribution Network Operator (DNO) services that could develop in the short to medium term (Ilex Energy Consulting 2004).

The study does not provide a detailed methodology that quantifies the benefit of DGs providing ancillary services. Rather, it derives a $/kW value based on estimates of the annual market value or the average price of the service. The study indicates that the value of these ancillary services to the system operator is very low and as such may not attract entry of DGs into these markets in their current state.

For frequency response, the report states:

> "The value of TSO Frequency Response is estimated to vary between £0.40/kW per annum for wind generation and £2.50/kW per annum for CCGT technology (excluding holding costs).
>
> As the only new distributed technology with a consistent capability to provide low frequency response services is wind power utilizing Doubly Fed Induction Generator (DFIG) technology, it is most appropriate to consider the impact of frequency response in this context.
>
> Upon entering frequency responsive mode, the generator might receive a payment of £4/MW/h (assuming the generator was capable of both primary and secondary response at current prices). So assuming a 100 MW wind farm was required to provide this service during summer weekends (26 occasions) for approximately 4 hours per night, the addition revenue earned would equate to £4 x 26 days x 4 hours x 100 MW = £41,200 per annum, i.e., £0.40/kW. In the context of a 100 MW wind farm with 30% utilization factor, the annual ROC revenue would equate to approximately £14m, i.e. payments for low frequency response services would add less than half of one percent to the wind farm's revenues.
>
> With the level of frequency response income being so low, it is questionable whether the wind developer would recover the costs of the required infrastructure.
>
> By contrast a 400 MW flexible CCGT earning approximately £50m per annum from energy sales, could earn up to an additional £1m per annum from frequency response services (£2.50/kW), which represents a 2% increase in revenues (Ilex Energy Consulting 2004)."

Similarly, it summarizes the value of standing (operating) reserve[37] as follows:

> "In the standing reserve market at present, the most flexible plant can earn approximately £23/kW52 per annum from standing reserve services. It should be recognized that the costs of entry for the lowest cost OCGT plant are in excess of £45/kW53 per annum. Consequently, the standing reserve market is not attracting new entry at present.
>
> Should the most effective provider currently be able to earn £23/kW per annum, the uncertainties associated with the delivery and the duration of service from micro-CHP could reduce this figure potentially below £7/kW. This figure is gross of any fee paid to the aggregator.
>
> At such levels, the service would not cover the costs of the infrastructure unless the communication infrastructure could be used to facilitate other services such as smart metering. Even if the value of the service were to triple, it is difficult to envisage an income of an extra £20 per annum (before infrastructure costs) influencing a customer's selection of heating system (Ilex Energy Consulting 2004)."

As a small piece of the analysis described above, the study authors endeavored to develop an estimate of the economic benefits associated with DG provision of VAR support. The methodology undertaken involved analysis of three cases in which DG provide various combinations of VAR and active power to the local distribution grid. The three cases examined are summarized by the study authors as follows.

- "DG generates active power only: by generating active power in distribution networks, distributed generation will reduce corresponding amounts of power imported from the transmission networks. This reduction in flow will reduce reactive consumption (losses) of distribution circuits and hence less reactive power will be imported from the transmission network.
- DG generates active and reactive power: by generating reactive power locally, distributed generation can supply some of the reactive demand to local loads and contribute to the supply of reactive losses in distribution circuits. This would normally result in a more significant reduction in the amount of reactive power imported from the transmission network.
- DG generates active and absorbs reactive power: by absorbing reactive power, DG will tend to increase the demand for reactive power. The net effect will be driven by the overall balance between the increase of reactive power demand by DG and reduction caused by exporting active power." (Ilex Energy Consulting 2004.)

Each scenario was analyzed within a simple generic model of the United Kingdom system. Note that as a simplification all DG was assumed to be distributed evenly across the country and equally split across the 11kV and 33 kV levels.

Study results indicate that as expected, the largest reduction in reactive power import occurs in the second scenario in which DG provides both active and reactive power supplies. Overall the study authors conclude that the reduction in reactive power requirements for each GW of installed DG is between 430 and 470 MVAR. If the midpoint of 450 MVAR per GW is assumed this would equate to £1.2/kW/year of installed DG, a relatively small percentage of the overall DG installation, operating, and fixed costs.

37 Standing reserve is similar to operating reserve in United States power markets.

Therefore, the report indicates that the value of ancillary services from DGs is low. However, it acknowledges that changes in the market may make such services more valuable to the operator with time, and then more relevant to DGs.

4.6 Major Findings and Conclusions

Ancillary services are essential for a reliable electric delivery system. DG can be used to provide ancillary services, particularly those that are needed locally such as reactive power, but also those that contribute to the reliable operation of the entire system, such as back-up supplies and supplemental reserves. However, there are not many documented instances where DG has been used by system operators for ancillary services. A number of studies have recently quantified the market value of ancillary services, which vary across the country depending on system conditions and constraints, resources, and demand growth. A small number of studies have explored the value proposition of using DG for ancillary services and these have found that there is potential for DG to cost effectively contribute to the provision of ancillary services.

Section 5. Potential Benefits of Improved Power Quality

5.1 Summary and Overview

For appliances or other electricity using equipment that are sensitive to micro-second perturbations in the flow of electricity, a high level of power quality is critical to avoiding damages and downtime. Voltage surges and sags, frequency excursions, harmonics, flicker, and phase imbalances comprise the major power quality concerns that can cause substantial economic impacts. Momentary interruptions of this type have been estimated to cost the U.S. economy about $52 billion annually. (LaCommare and Eto, 2004).

Despite the scale of this impact, the amount of analysis on the costs and remedies for power quality problems is not extensive. As Kueck et al. (2004) point out, there are several reasons for this:

- "Power quality incidents are often momentary—a fraction of a cycle—and hard to observe or diagnose.
- The growing digital load and the increased sensitivity of some of these loads mean that the definition of a power quality incident frequently changes. Ten years ago, a voltage sag might be classified as a drop by 40% or more for 60 cycles, but now it may be a drop by 15% for 5 cycles.
- Power quality involves design issues, such as the stiffness of the user's distribution system.[38]
- Often, power quality problems can best be addressed with local corrective actions, and these local devices are undergoing a revolution themselves, with changes occurring rapidly (Kueck et al. 2004)."

Some power quality problems are the result of problems caused by the utility's distribution system; some are caused by the customers themselves. In some cases, power quality problems originate with one customer and travel through the distribution system, and even the transmission system, to impact other customers. Some manufacturers are now equipping their products with filters and short-term energy storage devices to protect them against many power quality problems. Power quality problems are most often local problems, so the most cost-effective remedies tend to be local, not system-wide, solutions.

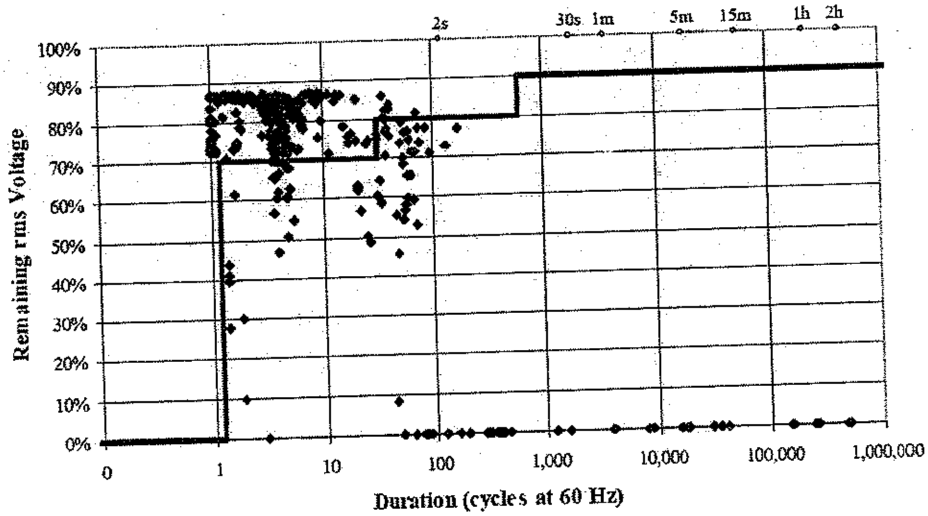
The continuous, and shifting, relationship between reliability and power quality is described by Gellings et al. (2004):

> "However, these reliability levels do not consider short duration power-quality disturbances. When potentially disruptive power-quality disturbances such as voltage sags, voltage swells, switching surges, poor voltage regulation, harmonics and other factors are considered, the availability of what we can call "disruption-free" power can be one or two orders of magnitude worse than a more standard interruption-based availability index."

38 A "stiff" system has a low enough impedance that sudden changes in current flow do not result in significant changes in voltage.

Data from a pilot monitoring project, summarized in Figure 5.1, shows the extent of existing power quality problems before the addition of distributed generation (DG). Those data points that lie above the ITI/CBEMA equipment curve should not cause problems for typical office equipment, while those that fall below the curve may cause the equipment to trip. In that project, the interruptions and sags for customers with single-phase service far outweighed those for customers served by a three-phase line.

Figure 5-1. Magnitude-Duration Summary of All Significant Power Quality and Electricity Reliability Events, 5/23/02 to 7/27/03, with ITI/CBEMA Curve Overlay



Source: Eto et al. 2004.

The curve shown in Figure 5.1 represents the suggested design tolerance for typical office equipment. There are also special purpose design guides for more sensitive industries (e.g., semiconductor manufacturing).

Voltage sags are typically caused by faults on the supply system. Sometimes a fault can result in an outage (a customer experiences an outage if they are supplied from the faulted portion of the system) but a fault almost always results in voltage sags over a wider portion of the supply system. As a result, customers experience many more voltage sags than actual interruptions (Electric Power and Research Institute 2003).

Depending upon the electronics and the interconnection rules, DG has the ability to improve some aspects of power quality, but the onus is on the DG unit(s) to avoid degrading other aspects. Both modeling and field data collection have been used to address the many unknowns and uncertainties of these DG/load/supply interactions. .

5.2 Power Quality Metrics

There are many measures and indices of power quality related to voltage support and stability and voltage and current waveforms. Voltage metrics include RMS voltage, power factor, flicker, System Average RMS Variation Frequency Index (SARFI), and MAIFI, described previously in Section 5. Metrics related to waveforms include total harmonic distortion (THD), K factor, Crest factor (the ratio of a waveform's peak or crest to its RMS voltage or current).

SARFI is a power quality index that provides a count or rate of voltage sags, swells, and/or interruptions for a system. The size of the system is scalable: it can be defined as a single monitoring location, a single customer service, a feeder, a substation, groups of substations, or for an entire power delivery system. There are two types of SARFI indices, $SARFI_X$ and $SARFI_{CURVE}$ (Brooks et al. 1998).

$SARFI_X$ corresponds to a count or rate of voltage sags, swell and/or interruptions below a voltage threshold. For example, $SARFI_{90}$ considers voltage sags and interruptions that are below 0.90 per unit, or 90% of a system base voltage. $SARFI_{70}$ considers voltage sags and interruptions that are below 0.70 per unit, or 70% of a system base voltage. And $SARFI_{110}$ considers voltage swells that are above 1.1 per unit, or 110% of a system base voltage. The $SARFI_X$ indices are meant to assess short-duration RMS variation events only, meaning that only those events with durations less than 60 seconds are included in its computation.

$SARFI_{CURVE}$ corresponds to a rate of voltage sags below an equipment compatibility curve. For example $SARFI_{CBEMA}$ considers voltage sags and interruptions that are below the lower CBEMA curve. $SARFI_{ITIC}$ considers voltage sags and interruptions that are below the lower ITIC curve. Lastly, $SARFI_{SEMI}$ considers voltage sags and interruptions that are below the lower SEMI curve. These curves do not limit the duration of an RMS variation event to 60 seconds; therefore, the $SARFI_{CBEMA}$, $SARFI_{ITIC}$, and $SARFI_{SEMI}$ are valid for events with durations greater than ½ cycle.

Total harmonic distortion (THD): The ratio of the RMS value of the sum of the individual harmonic amplitudes to the RMS value of the fundamental frequency.

K factor: The sum of the squares of the products of the individual harmonic currents and their harmonic orders divided by the sum of the squares of the individual harmonic currents (Kueck et al. 2004).

Crest factor: The ratio of a waveform's peak or crest to its RMS voltage or current (Kueck et al. 2004).

Flicker: A perceptible change in electric light source intensity due to a fluctuation of input voltage. Note that this definition includes two aspects: the human perception and the voltage fluctuation. Voltage flicker is one of the most significant concerns utilities currently have with respect to DG's impact on circuit power quality. Flicker, voltage flicker, light flicker, and lamp flicker are different names for the same phenomenon, a fluctuation in power system voltage that results in a visible change in the output of lighting systems (Kingston et al. 2006).

> "For a DG system running in standalone mode (islanded), the disturbances of loads, such as start and stop of an air conditioner, refrigerator, compressors, washing machines and cooktop, cause sudden load current changes to the DG inverter. In turn, these sudden current changes cause voltage drops due to the output impedance of the inverter, and thus, its AC output voltage will fluctuate causing light flicker.... In grid parallel mode, flicker is less of a problem since the grid supports the AC voltage. However, the flicker problem may still take place for a weak line (GE Corporate Research and Development 2003)."

> "Modern power electronic inverters can be viewed as supplying clean power. However, there may be transients resulting in flicker with some types of DG, particularly wind and photovoltaic energy systems as a result of varying output power. The effect on the voltage at the point of connection will depend upon the strength of the grid to which the DG is connected and the speed

of response of its voltage regulator. On the positive side, DG equipped with a power inverter interface can be used to alleviate power quality problems present on the AC grid by independently controlling the real and reactive components of the power injected into the ac grid. Under these conditions, the distributed generator can be configured to behave as an active power conditioner or compensator by injecting reactive power to: regulate the voltage at the point of coupling, regulate the total plant power factor, or to mitigate voltage flicker. The power inverter can also correct voltage sag, but the rating of the inverter may have to be significantly increased to fulfill this function. The effect of DG will usually be limited to the bus to which the system is connected (Joos et al. 2000)."

Harmonics: Depending upon the DG generator winding, a DG unit can introduce significant harmonics into the grid, although this problem is minimized if the customer load is located nearby. On the other hand, power electronic interfaces can be designed to not only prevent DG-related harmonics, but also to improve harmonics and provide extremely fast switching times for sensitive loads (Kroposki et al. 2006).

5.3 Simulated and Measured Impacts of DG on Power Quality

Energy storage technologies, power electronics, and power conditioning equipment are important components in certain DG systems and applications, such as roof top photovoltaic arrays. These devices are very useful in addressing power quality problems. Indeed, energy storage, in the form of uninterruptible power supplies (usually batteries) is one of the primary mechanisms employed by equipment manufacturers to protect sensitive equipment from voltage spikes and other potentially damaging power quality problems. However, there are not many other examples of using DG to address power quality problems.

5.3.1 Simulation Analysis

Simulations are valuable because they can be used to explore system designs before they are built. Simulations are also used to evaluate conditions that are more extreme than those likely to be encountered in practice, and can therefore define the boundaries of good and bad impacts of any technology.

The "Virtual Test Bed" models the utility's power delivery system, loads, and DG (GE Corporate Research and Development 2003). A broad series of parametric models were run to examine the influence of the amount of DG on a feeder, the location of the DG relative to the loads (lumped at the beginning, middle, or end or the feeder, or uniformly distributed along the feeder), the effects of inverter-based and rotating DG technologies, DG local voltage regulation strategies (either operation at a power factor of 1.0 or the DG provides voltage regulation based on local conditions), two radial feeder lengths, and the presence or absence of capacitor banks.

The power quality case studies included voltage regulation, harmonics, flicker, DC current injection, grounding, and unbalanced grid. The voltage regulation cases studies were especially useful because they provided guidance on the maximum amount of DG that can be prudently added to a feeder. The analysis found that if the DG is located at end of a feeder farthest from the substation, the maximum installed DG capacity should be no more that 15% of the feeder's peak load. It also found that if the DG is uniformly distributed along the length of a feeder, the maximum DG capacity could be as great as 50% of the feeder's peak load. Finally, the analysis found that if the DG is located at the substation, the penetration level is not an issue (GE Corporate Research and Development 2003).

The analysis also examined whether or not voltage regulation services (albeit the modeled regulation service was limited by a number of assumptions) provided by the DG would be effective. The results for this analysis were mixed, with some case studies showing benefits, others no impact, and a few cases showing that local regulation by a DG actually aggravated feeder voltage regulation problems.

The case studies that examined the DG impact on load-induced flicker found that:

> "Rotating equipment, including DGs, increases short circuit strength and therefore improves flicker performance.
>
> Inverter-based DGs operating in a constant current mode without a voltage regulation function have a very slight inherent benefit on flicker performance.
>
> Inverter-based DGs have the potential to provide substantial benefit on flicker if equipped with controls that provide voltage regulation or some other functional equivalent.
>
> The case studies that examined the ability of DG power output fluctuation to cause flicker found voltage fluctuations just below the human threshold of perception, but did illustrate the potential for DGs to cause flicker (GE Corporate Research and Development 2003)."

In another simulation, a team from Virginia Polytechnic Institute modeled a real circuit located in southern California to examine the effect of proposed DG installations on voltage flicker. They performed both a theoretical evaluation and a computer simulation to examine a series of worst-case analyses for the four most likely DG installations on that suburban circuit (Kingston and Stovall 2006). These analyses compared the voltage flicker associated with DG system starting and stopping and DG system output fluctuations to the voltage fluctuation thresholds at different frequencies defined in several industry standards (IEEE 141-1993; IEEE 519-1992; IEC 61000-4-15-2003; IEEE 1453-2004).

The theoretical analysis showed that the distribution system is weaker at locations farther away from the substation. If a significant level of DG is located at a relatively weak location, voltage flicker problems may be experienced, although smaller DG systems placed at the same weak location will produce no detectable voltage flicker. A higher level of DG can be safely installed at stronger locations. Two of the proposed DG systems in the analysis would not cause noticeable flicker even if the DG system failed up to one time per hour. One of the DG systems could fail up to 24 times per minute and still cause no voltage flicker problem anywhere in the circuit. The fourth DG unit was located in a robust portion of the grid and would not cause flicker problems under any failure frequency (Kingston and Stovall 2006).

5.3.2 Measured Impacts

In order to investigate these concerns, a monitoring program was set up to examine both the effect of DG on the grid and the effect of the grid on the DG for 11 generators at 6 sites in California. This program logged included over 230,000 hours of data (Overdomain, LLC, and Reflective Energies, 2005b). They summarized their results as:

> "The most modern power quality metering was used, capable of capturing waveforms at 256 samples per cycle (over 15,000 measurements per sec). Power quality parameters measured

included voltage sags and swells, frequency, wave form, harmonic distortion, flicker and other transients.

The monitoring to date showed that so far, for the sites selected, there is very little impact of DG on the distribution system. Similarly, the impact of the distribution system on the DG has been minimal. ...increasing penetrations of DG are unlikely to create challenges because the current growth rate of DG is slow, while experience with DG is growing more rapidly."

The following conclusions may be made for the data analyzed from the DG Monitoring project from mid-2002 through October 2004:

"The critical point to measure impact on the grid is the point of common coupling (PCC). Power quality at the PCC was very good when compared to the power quality benchmarks established by Electric Power Research Institute (EPRI) and Southern California Edison (SCE). One measure of power quality is SARFI event rates. The average PCC monitor logged an average of 13.93 "$SARFI_{90}$"voltage sags and interruption (voltage drops below 90% of rated voltage) events per year, which is far lower than the 54 events per year in the EPRI distribution system power quality study and 47 events per year in the SCE study.

Power quality at the DG itself was also very good. The average DG monitor at the DG experienced averaged about 11.20 $SARFI_{90}$ events per year. This was less than half the event rate at the PCC. This indicates that the DG is not impacting power quality problems into the distribution system. It also indicates that the distribution system is having no negative effects on the DG.

$SARFI_{50}$ measures larger events (voltage dips over 50% of rated voltage). $SARFI_{50}$ events at the PCC were less than one per year, compared to 5 per year in the SCE study and 12 per year in the EPRI study. The one system that exported power did not show any increased impact on the grid resulting from the export. There are several PV systems exporting small amounts of power with no known consequences. There may be room to allow some export of power in future. Export will be given a priority for selection of sites in future.

None of the other power quality factors, such as flicker and harmonics were of concern.

No voltage swells of any consequence were encountered during the entire monitoring program (Overdomain, LLC, and Reflective Energies, 2005b)."

Although utilities collect and report system reliability performance, they are less likely to determine and report the performance of other power quality characteristics of the supply that can affect end-users. One report has collected the results from a number of power quality monitoring programs:

"The most complete system performance benchmarking project to date is the EPRI Distribution Quality project (EPRI 1996). This project characterized power quality based on two years of monitoring at almost 300 distribution system locations across the United States. Performance was characterized in all categories of power quality. Perhaps the most valuable part of the benchmarking was that assessment of expected voltage sag performance for end-users supplied from the distribution system.

"Other benchmarking projects were performed in Canada, Europe, South Africa, and by other individual utilities. For instance, PowerGrid in Singapore conducted an extensive evaluation of expected voltage sag performance in Singapore and compared the performance with the results of other major benchmarking projects. PowerGrid is an example of a utility that has made tremendous investments in the system infrastructure to assure reliability and the highest quality of service for the variety of critical industrial processes (e.g. semiconductor manufacturers) that they supply. [Table 6.1] summarizes the comparison (Chang et al. 2001; NRS 048-2:1996; Davenport 1991). Obviously, even with a completely underground system and high levels of investment, voltage sags can still be important (EPRI 2003)."

Table 5.1. Comparison of Expected Performance Levels Estimated From Different Benchmarking Projects

	SARFI-10*	SARFI-70	SARFI-80	SARFI-90
Power Grid – Singapore	1.0	8.5	10.6	14.3
EPRI DPQ Project (US)	4.6	17.7	27.3	49.7
UNIPEDE Mixed Systems (Europe)	16.0	44.0	NA	103.1
UNIPEDE Cable Systems (Europe)	1.4	11.0	NA	34.6
South Africa	9.0	47.0	78.0	153.0
* SARFI-10 is a measure of the number of voltage sags that can be expected with a minimum voltage magnitude below 10%.				

Source: Electric Power and Research Institute 2003.

5.4 Value of Power Quality Improvements

The economic impact of poor power quality can be particularly large from an end-user perspective. Moskovitz et al. (2002) mentions that:

> "For modern electronic-based businesses, it is not only outages that hurt but unstable power quality as well. Many high tech businesses, from Web-servers to bio-tech laboratories, need a very high level of power quality. .... Today, in the 24-hours-a-day, seven-days-a-week information age, many businesses operate computer-driven equipment with availabilities of 99.999% or even 99.9999%, ... Very brief sags in voltage or harmonic distortions that used to go entirely unnoticed by most customers can be devastating to customers using sensitive electronics. It is as little as 8/1000 of a second to crash a computer system, often destroying data at the same time. Fixes to avoid power surges are usually cheap but remedies for avoiding power sags are not so cheap. For these businesses, often redundant systems can be a very cost-effective means of ensuring the required power quality and reliability levels."

For example:

> "The First National Bank of Omaha in Omaha, Nebraska, began operating its carefully designed independent distributed power system for its power-sensitive credit card processing center in May 1999. The bank is the nation's seventh-largest credit card processor and the provider of similar services to many other banks in its region. It faces losses of about $6 million for every hour of power outage. Following the failure of a backup battery system in the early 1990s, the bank looked around for a better way to ensure itself of the continuous high-level power quality and reliability its 24-hour, uninterrupted operation required. The bank's critical computer operations are now served by two redundant sets of fuel cells (four in all) as well as a separate redundant set of diesel engines. The remainder of the building, with less critical operations, is connected to two separate electric feeders, installed from different substations (Moskovitz et al. 2002)."

With the economic benefit of on-site cogeneration and small power production, to improving power quality could also be large for the utility because the utility would have to invest less in improving grid-wide power quality. Gumerman et al. (2003) indicate that "…costs can potentially be lowered because the wider power system does not have to be tailored to sensitive loads."

Although the economic benefits to both the utility and its customers from power quality improvements could be large, estimating these economic benefits could be difficult and uncertain. This is because there are no markets specifically for power quality. Customers cannot ask to be put on lower, or higher, power quality rate schedules or service agreements.

It is possible, in theory, to estimate the market value of improved power quality from the value of improved reliability, to the extent the specific industry and the duration of the outage are known. However, there is no clear cut distinction or defining line between reliability and improved power quality. Both of these factors form a continuum and it is difficult to disaggregate their market values into separate components. Similar to reliability, improved power quality provides economic benefits in the form of deferred generation and transmission and distribution (T&D) capacity. If DG power can substitute feeder loading and enhance reliability by avoiding T&D and/or generation capacity upgrades, then the economic benefits can be determined from deferred T&D and/or central station capacity.

5.5 Major Findings and Conclusions

Power quality problems tend to be localized phenomena and are not often system wide concerns. With the increasing use of electronic components for appliances and equipment in homes, offices, and factories, customers are increasingly concerned about power quality, and potential damages to equipment and business operations. In certain instances, DG can be used to address power quality problems, particularly when the systems involve the use of energy storage, power electronics, and power conditioning equipment. However, there are also examples where the use of DG has actually led to power quality problems.

Section 6. Potential Benefits of Distributed Generation to Reduce Land Use Effects and Rights-of-Way

6.1 Summary and Overview

Central station power generation facilities, and the transmission and distribution (T&D) equipment and systems that carry power across vast regions of the country, have significant land use impacts (Rawson 2004). Under certain circumstances, it is possible that the expanded use of DG could lead to a decrease in the amount of land required for electricity-generating facilities and rights-of-way (ROW) for T&D corridors. However, DG has its own land use impacts. These may include reductions in available open space, in addition to costs associated with not-in-my-backyard (NIMBY) concerns.

This section describes the potential benefits of DG to reduce the amount of land use for electricity production, and its effects on rights-of-way (ROW) for transmission and distribution. Section 1221 of the Energy Policy Act of 2005 contains provisions for DOE to identify regions affected by transmission congestion and designate "national interest electric transmission corridors. The purpose of this provision is to assist with the siting of interstate electric transmission facilities. Local community electricity needs, which can be met with DG, may indeed dovetail with opportunities to conserve open space and reduce requirements for transmission corridors and distribution facilities, and address needs for siting and permitting that can come with expanding existing or obtaining new ROW.

6.2 Land Required By Central Station Energy Development Compared to DG Development

Spitzley and Keoleian (2004) have estimated the required land resources to create a typical conventional electricity-generation facility, comparing life cycle assessments for electricity-generation facilities fueled by biomass and hydrocarbon-based fuels, such as coal and natural gas. The amount of land required to site a central power facility is dependent upon the (1) fuel type used to generate electricity and, (2) the generation technology (e.g. turbine plant process) (Spitzley and Keoleian 2004). These researchers use weighted averages of the site requirements and fuel sources used by electricity generating facilities throughout the United States. This weighted average function is presented below.

$$L = \sum_{i=1}^{5} X_i \times W_i$$

where:

L = Weighted Average Land use for a Central Power Source
X_i = Land Area Required for a *ith* Central Power Source
W_i = National Percentage of Electricity Generation for the *ith* type
i = Number of Assumed Generation Facility Types where i ranges from 1 to 5

Based on this equation, a total weighted average for various fuel sources is presented in Table 6.1 and is equivalent to 492.86 hectares (ha) or 1217.86 acres. This estimate, then, is the average amount of land required for a central station electricity plant, given various fuel sources. The weighted average is greater than the amount of land required solely for coal and natural gas electric generation facilities due to the amount of land required for nuclear and wind turbine facilities. These land-use estimates in hectares, as predicted by Sptizley and Keoleian (2004), in addition to the proportion of fuel sources used by the electricity generation industry, are presented in Table 6.1.

Table 6.1. Land Use for Typical Central Power Source Facilities[39]

Fuel Type[40]	Generation Technology/Site	Area Required for Utility Site Operations	Actual National Percentage (2004)	Adjusted National Percentage	Weighted Average Acreage (per MW)[41]
Coal	Typical U.S. Direct-Fired Pulverized Coal Boiler Plant	129 ha	49.80%	51.82%	165.19
Natural Gas	Integrated Gasification Combined Cycle Plant	40.5 ha	17.90%	19.92%	19.94
Nuclear	Pressurized Reactor Plant	1814 ha	19.90%	21.92%	982.54
Wind	Ridge Site Wind Farm	520 ha	1.15%	3.17%	40.72
Biomass	Low Pressure Indirectly Heated Gasifier Combined Cycle Plant	121 ha	1.15%	3.17%	9.49
Other	No Data Available		.6%		
Petroleum	No Data Available		3.00%		
Hydroelectric	No Data Available		6.50%		
Total			100%	100.00%	1217.86

Source: U.S. Department of Energy, Energy Information Administration 2005.

Less data is available on the land use impacts of distributed generation (DG) development. Resource Dynamics Corporation (RDC) has estimated, using various DG installations, the possible "footprint" associated with DG facilities (RDC 1999). These estimates are presented in Table 6.2.

The difference in the data estimates presented in Table 6.1 and Table 6.2 is used in this section to forecast potential land savings from distributed generation facilities. Additional information pertaining to the data in these tables is included in Appendix B and C of this report.

39 This table does not include hydro, petroleum, and other gases. Therefore the additional percentages have been applied across the four major energy sources, Coal, Natural Gas, Nuclear, and Renewables. The percentages have been equally increased across all fuel and technology types in the table.

40 The land area estimates in Table 6.1 are dependent on an assumed level of MWh for each electricity plant type. These estimates are: Coal – 202 MW, Natural Gas – 378 MW, Nuclear – 467 MW, Wind – 7 MW, Biomass – 81 MW, and an overall average for all facilities – 227 MW.

41 These acreage estimates have been calculated from the original source data, given in hectares.

Table 6.2. Land Use for Typical Distributed Generation Resources Facilities

Technology	Diesel Engine	Natural Gas Engine	Microturbine	Building Integrated Photovoltaic Array[42]	Fuel Cell
Assumed Size (sq ft/kW)	0.265	0.325	0.25	180/0[43]	0.9

Source: Resource Dynamics Corporation (RDC) 1999.

6.3 Land Area Required for Electricity Transmission Lines Rights-of-Way

Data sources on land area required for new electricity transmission line rights-of-way (ROW) are limited. The U.S. Department of Energy, Energy Information Administration (EIA) has estimated the impact of increasing numbers of electricity generating units in the United States and the need for resulting electricity transmission lines through time to quantify the need for new transmission lines, given the construction of new central power sources (Energy Information Administration 2003). EIA data for 2003, the most recent year available, is described below:

- The net number of electricity generating units in the United States has increased by 15 units.
- 1,140 miles of new transmission lines have been built.
- Approximately 76 miles of new transmission line have been built for each new electricity-generating unit.

The width of these lines - and therefore the total acreage required for them – can vary based on required voltage. For this report, data from American Electric Power (AEP 2006) estimates ROW line width requirements, as shown in Table 6.3 below, that will be needed to transmit 2,400 MW over 100 miles.

Table 6.3. Assumed Transmission Line ROW Width

	Transmission Lines Needed to Transmit 2,400 MW over 100 Miles			
Transmission Voltage	765 kV	500 kV	345 kV	138 kV
ROW Width	200 ft	175 ft	150 ft	100 ft

This data is based on the following assumptions:

- The average transmission line ROW width is 156.25 feet.
- The average mileage required for a new electricity generating unit is 76 miles.
- 9.21 acres of aggregate ROW are needed for one new central power source.

6.4 Acquisition Costs and Rights-of-Way

The "Across" or "At-the-Fence" value (ATF) is a common technique for valuing property. The ATF value is less than a penny per square foot (sq ft) for some western rural counties, but exceeds $2,500 per sq ft (in 1989 dollars) or $4,021 (in 2006 dollars) for downtown New York (TeleCommUnity Alliance

42 Information from this column was not derived from Omer et al. 2000. The parameter estimate is similar to additional publications that have presented data to estimate sq ft/kW.

43 Unlike energy systems installed on the ground, outside existing buildings, rooftop-installed photovoltaic systems do not consume additional land; the figures given are therefore for reference purposes only. For this analysis, rooftop-installed photovoltaic systems will be given a land-consumption value of zero.

2002). This land value estimate highlights the variation in rural and urban lands that are utilized for rights-of-way. On the other hand, "comparable transaction valuation" (CTV) examines information from the real estate market and uses sales and transfers of similar assets to establish a value for a given property (Reynolds 2003).

To arrive at an appropriate value of land, other considerations are imposed on these estimates that relate to the particular nature of ROW acquisition. Specifically, ROW acquisition costs typically include the value of property located on the land and the actual value of the land resources. Therefore, regions of the country with higher building density and highly valued land resources incur significant ROW acquisition costs. For example, metropolitan lands are typically higher priced on a per-acre basis and are developed at higher densities in comparison to rural lands. In fact, the Florida Agricultural Land Value Survey reveals that per-acre land values vary considerably depending on their location (Heimlich 2003). For example:

- Agricultural lands in Florida metropolitan counties range in value from $13,167 to $58,813 per acre in 2003 or $14,304 to $63,892 in 2006 dollar values.
- In comparison, rural agricultural lands values in Florida range from $4,312 to $6,500 or $4684 to $7,061 per acre in 2006 dollar values.

Designation of a right-of-way does not necessarily make the property unavailable or too costly for its owner for future use. Acquisition costs may relate more to a change in the characteristics of the property rather than to the value of the property itself. This may take on three basic forms; the value of direct damages to the property due to construction, the loss in property value because of diminished access, and/or the loss in property value because of the increase or decrease of the value of any remaining remnants of the property not granted as part of the ROW. Rights of way thus have a very real cost, a cost that can vary depending on the use of land for central station power development of distributed generation development.

6.5 The Impact of Transmission and Distribution Costs on Rights-of-Way

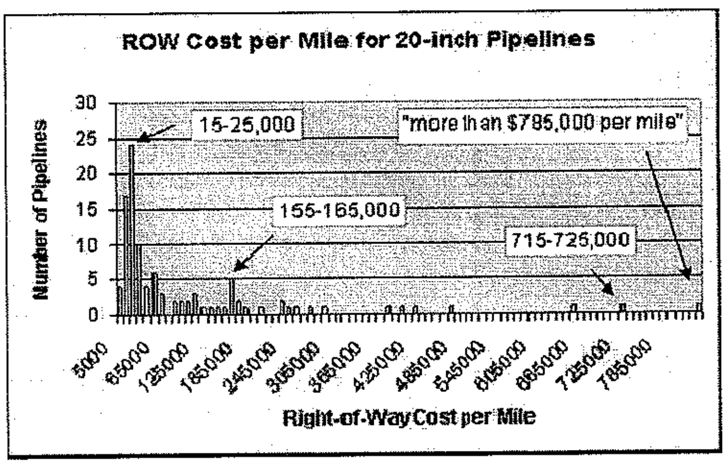
There are approximately 350,000 miles of electrical transmission lines and two million miles of distribution lines in the United States (Abt 1994). An analysis of U.S. Department of Energy, Energy Information Administration (EIA) data indicates that the density of distribution lines ranges from about 500 to 2,000 miles of lines for each billion kWh of electricity delivered, with an average of about 1,000 miles per billion kWh (Energy Information Administration 2006). The total value of the ROW associated with these lines could easily be as much as a trillion dollars based on a conservative estimate of $400,000 per mile of line.

A recent AEP-proposed high-voltage (765-kV) line, 200 feet wide and crossing 550 miles of eastern United States farmlands and mountains, is expected to cost an average of $940,000 per mile. AEP has considered multiple options for the power line facility, specifically the use of lower-voltage lines (500 kV, 345kV, and 138kV). Because the lower-voltage lines are limited to disproportionately lower loads compared to the 765-kV line, multiple, parallel sets of lines would be needed. With each step-down in voltage, the total width of the required ROW increases. The total width of the ROW for the lowest-voltage lines is actually 12 times that of the 765-kV line, 2400 feet compared to 200 feet, resulting in significant savings in land and other ROW costs by pursuing the 765-kV line. This information is presented above in Table 6.3. Nevertheless, AEP has revealed that it will construct the 765-kV line and will expend ROW acquisition costs of $39,075 per acre (Energy Information Administration 2003).

Parker (2004) on the other hand, has studied construction costs from more than 20,000 miles of natural gas, oil, and petroleum product pipelines for 893 projects in the United States. The study reveals much about the cost of ROW for pipelines. Pipeline ROWs are quite similar to power line ROWs in that large amounts of land are affected.

Parker (2004) also has found that the ROW portion of pipeline costs is not the result of the pipeline diameter and length alone. Cost variability is also attributed to the manner in which pipelines are laid next to existing lines, while in other cases, the location of an ROW causes it to be very expensive. Looking further at the diameter factor reveals that there is no simple relationship between ROW cost and pipeline diameter. Parker's research does claim that ROW costs for 36-inch pipelines are substantially higher than those for 6-inch lines, \$50,000 versus \$20,000 or \$52,875 versus \$21,150 in 2006 dollars. The reason for this is not immediately obvious, but it may be due to the fact that the 30-inch and larger pipelines are nearly always very high-pressure lines requiring wider ROW, and that they are less adaptable to alternative uses. The lower cost as a function of diameter in the 10-24 inch range may relate to the location of the lines, with smaller lines associated with distribution systems in populous and industrially developed areas.

Figure 6-1. Comparison Between Number of Pipelines and ROW Costs



Source: Parker 2004.

The dataset for 20-inch pipelines may be analogous to electric power distribution lines, given that the ROW can range between 50 to 200 feet wide in some instances. Figure 6.1 presents this variation in 20-inch pipelines.

The figure indicates a mode of \$15,000 to \$25,000 per mile, while the range is from about \$5,000 to "more than \$785,000 per mile" (Parker 2004). In 2006 dollars these estimates equate to a mode of \$15,862 to \$26,437 and a range from \$5,287 and \$830,149. Although the data does not provide ROW width information, it can be assumed that most of these ROWs are 100 feet or less in width. Based on the assumed 100-foot width, the per-acre costs would range from a low of about \$400 to more than \$60,000 with a median of perhaps \$3,000. In 2006 dollars these estimates equate to \$423 to more than \$63,450 with a median of \$3,172. Note that these values would double if a 50-foot width were used.

6.6 The Impact of Maintenance Costs and Requirements on Rights-of-Way

Acquiring electric transmission rights-of-way includes estimating future maintenance costs. Electric transmission ROWs are typically maintained to minimize operational interruptions, increase safety, and reduce erosion and water pollution through landscape planning and vegetative control. For example, electric utilities, regional transmission organizations, and public utilities use vegetative control methods, such as mowing and hand pulling; biological and chemical controls; utilization of herbicides, and use of animals to control unwanted vegetation (Robinson 2003). Rights-of-way maintenance costs can be high; for example, in 2003, Duke Energy reported a total of $40 million in ROW maintenance costs (Duke Energy 2003).

In addition to physically maintaining open lands associated with electric transmission ROW, electric transmission firms are typically required to upgrade existing transmission lines through various activities such as reconductoring, bundle conductoring, and retension of existing conductors. In terms of affecting transmission line ROW, reconductoring, removing existing conductors, and installing larger conductors have the greatest impact on land use requirements for a ROW. In turn, additional ROW costs can be incurred by upgrading – or enlarging the width of – transmission lines. An example of the impact on ROW width requirements from various transmission line kV levels is presented in Table 6.4 (Glodner 1994).

Table 6.4. ROW Requirements Based on Transmission Line kV Levels

Nominal Line (kV)	ROW Width (Meters)	ROW Width (Feet)
69	23-30	75-100
115	23-38	75-125
138	30-46	100-150
161	30-46	100-150
230	46-61	150-200

This data illustrates that a single-level increase in kV levels does not necessarily require an expansion of ROW width, except for an increase from 161 to 230 kV (U.S. Department of Energy, Western Area Power of Administration, 2003).

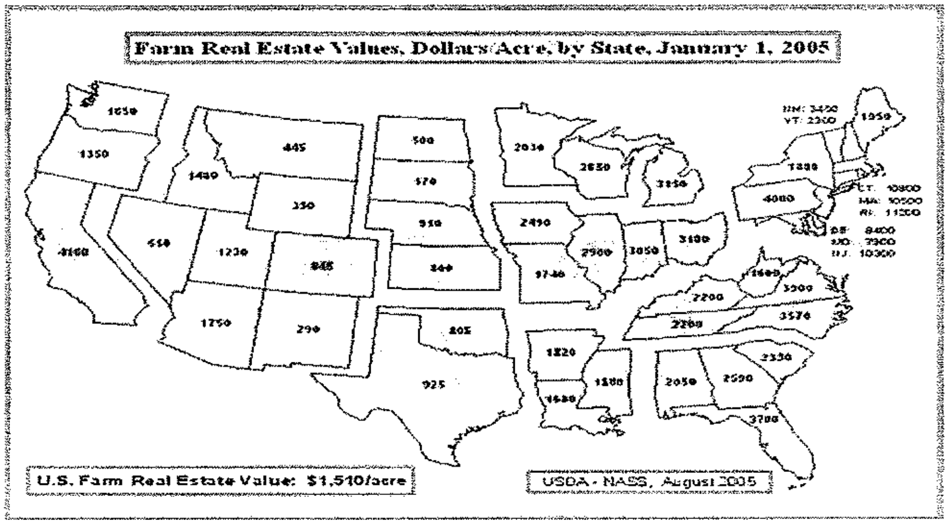
6.7 Land Values in Urban and Suburban Areas

Central power facilities in the U.S. are sited in rural, urban, and suburban areas. Land values in urban areas have greater per-acre values in comparison to rural areas and even greater values in metropolitan areas. Data regarding per-acre land values in urban areas are available in municipality or township tax records and are difficult to estimate. Additionally these land values vary drastically across the United States, making it difficult to estimate national averages.

Nevertheless, the USDA Natural Resources Conservation Service (NRCS) and National Agriculture Statistics Service (NASS) maintain a database of land characteristics and land values for agricultural lands located in rural and urban regions (Heimlich 2003). These data resources have been used by the USDA Economic Research Service (ERS) to estimate the value of agricultural development rights located in urban regions. This data is presented in Figure 6.2.

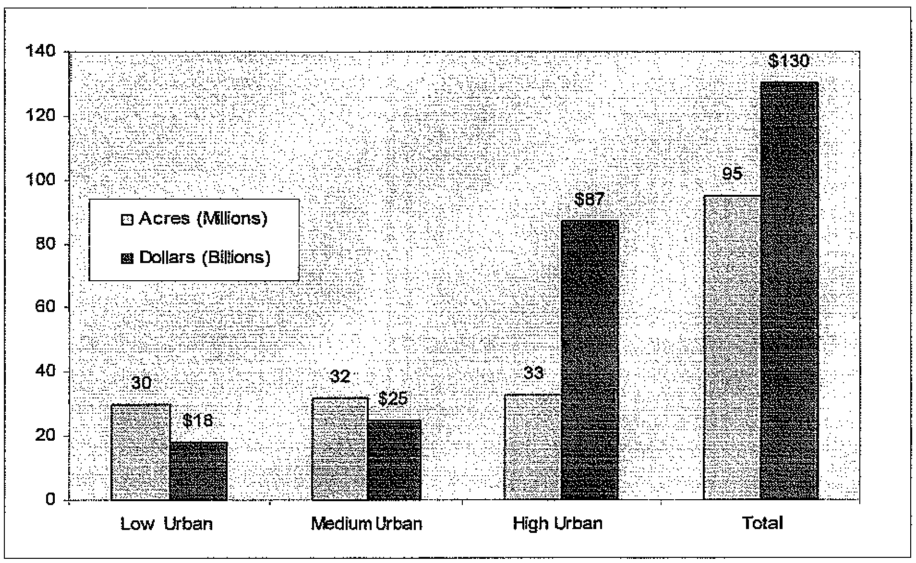
NASS also provides state-by-state averages for agriculture land values. Figure 6.3 presents average farm real estate values based on USDA data for each state in 2006.

Figure 6-2. State-Level Agricultural Land Real Estate Values



Source: USDA 2006.

Figure 6-3. Estimated Total Value of Agricultural Land Development Rights



Source: Heimlich 2003.

Table 6.5 presents information on the value of Florida agricultural lands in metropolitan and non-metropolitan areas. Agricultural land values in metropolitan areas increased from 2002 to 2003 by 15% and are significantly greater than land values in non-metropolitan counties (Reynolds 2003). For example, on a per-acre basis, agricultural land in metropolitan counties within 5 miles of a major town is roughly $19,000 greater than land in non-metropolitan counties within 5 miles of a major town.

As previously stated, development of central power stations requires extensive land resources and doing so in a metropolitan area is similarly costly. Given the relatively high cost of land in densely populated communities, the land use benefit of distributed generation might be significant for such areas.

Table 6.5. Agricultural Land Values in Florida – Per Acre

Florida Metropolitan Counties	Average Per-Acre Land Values (2002)	Average Per-Acre Land Values (2003)	Average Percentage Change
Less Than 5 Miles to Major Town	$19,714	$23,980	15%
Greater Than 5 Miles to Major Town	$11,500	$13,070	15%
Less Than 5 Miles to Major Town (2006 Dollars)	$22,016	$26,781	15%
Greater Than 5 Miles to Major Town (2006 Dollars)	$12,843	$14,597	15%
Florida Non-Metropolitan Counties			
Less than 5 Miles to Major Town	$5,061	$5,404	7%
Greater Than 5 Miles to Major Town	$3,671	$3,979	8%
Less Than 5 Miles to Major Town (2006 Dollars)	$5,652.09	$6,035.15	7%
Greater Than 5 Miles to Major Town (2006 Dollars)	$4,100.12	$4,444.09	8%

Source: Reynolds 2003.

6.8 Land-Use Costs Associated with Distributed Generation

This subsection compares the cost of land acreage associated with a number of distributed generation technologies and systems with the cost of land acreage required by central power systems. This comparison is based on the following assumptions:

- Multiple DG equipment and systems are combined in one 250 MW capacity campus, including 2 MW at a building-integrated photovoltaic (PV) facility; a residential building with a 50 MW CHP plant that is located separately; a 98 MW CHP industrial facility; and a 100 MW CHP commercial facility where half is integrated into buildings and other half is located in separate power houses.
- Central power sources individually generate 250 MW.
- Fuel sources for central power generation include coal, natural gas, and nuclear.
- Given the limited data on land use, the comparison is not generated for a specific city or region but is based on typical DG facilities and DG technologies.

This comparison is based on data on the amount of land required and the kW generated from a central power source and the land and kW from multiple DG facilities. Specifically, the parameter used for the comparison of the electricity choices is land use per kW, or square foot per kW.

Table6.6 illustrates that natural-gas-fueled central power plants require less surface area than either nuclear or coal plants relative to the level of electric generating capacity at that plant.

Table 6.6. Land-Use Parameters for Central Station Plants

	Coal	Natural Gas	Nuclear
Assumed Size (sq ft/kW)	69	12	42
Total Assumed MW	100	50	100
Total Land Use (Acres)	321	100	455

Source: Spitzley and Keolian (2004).

Similarly, previous research from RDC reveals the estimates for land use per kW for DG systems, presented in Table 6.7.

Table 6.7. Land Use Parameters for DG Facilities

	Diesel Engine	Natural Gas Engine	Microturbine	Industrial Turbine (Assuming CHP)	Building Integrated Photovoltaic Array	Fuel Cell
Assumed Size (sq ft/kWh)	0.265	0.325	0.25	0.61	0.00	0.9
Total Assumed kW	5,015	3.025	115	Greater than 10,000	1.6	1,550
Total Footprint (sq ft)	1,328	983	28	6,100	0.00	1395

Source: Spitzley and Keolian (2004).

Each of the parameters presented in Table 6.7 can vary based on the location of the DG facility. For example, the combined heat and power (CHP) system is presented as an industrial turbine that is operating separately from an industrial facility. Conversely, a CHP unit can be placed inside as an integral part of the building. Thus, the resulting surface area used for the unit can vary substantially. Given the previously stated assumptions, the total land area required for DG facilities is estimated in Table 6.8.

Given these parameters (sq ft/kW), the total land use for these DG facilities is estimated to be roughly 2.39 acres. Assumptions supporting this analysis are based on the utilization of numerous CHP facilities and building-integrated solar photovoltaic systems. Combined heat and power is the most land-use-efficient DG technology option. On the other hand, if additional DG technology options are used, such as non-CHP engines or turbines installed outside of existing facilities, a much more extensive land-use impact might result.

Table 6.8. Estimated Land Use Requirements for Distributed Generation Facilities

	Building Integrated Photovoltaic Array	Residential Buildings with External CHP Facility[44]	Industrial CHP Turbine	Numerous CHP for Commercial Facilities[45]	Total Land Use Utilized for this Estimate (Acres)
Sq ft per kW	0.0	0.14	0.61	0.38	
Total Assumed Electricity	12 MW	50 MW	98 MW	100 MW	
Total Land-use by Each DG Technology (acres)	0.00	0.16	1.37	0.86	2.39

Source: Spitzley and Keolian (2004).

By comparison, land use estimates required for three types of central station generation facilities are presented in Table 6.9.

Table 6.9. Estimated Land Use Requirements for Central Power Stations

	Coal	Natural Gas	Nuclear
Assumed Size (sq ft/kW)	69	11	42
Total Land Use (square footage) assuming 250 MW	17,263,206	2,882,065	10,591,156
Total Land Use (acreage) assuming 250 MW	396	66	243

Source: Spitzley and Keolian (2004).

As shown in the above tables, central power stations require much more land than DG facilities. As presented in Table 6.8, the total land used by DG facilities that generate a 250 MW of electricity is calculated to be 2.39 acres and a central power source for the same electric generating amount ranges from 66 acres to 400 acres. The land use savings that accrue to the distributed generation scenario therefore ranges between 63.6 and 396 acres. The resulting land-use benefit value, assuming the low-range land value of $171 and an upper-range value of $5,234 per acre, can vary from $9,616 to $2,020,481.

This comparison does not include a reduction in ROW acquisition costs, which would add another $13,170 to $18,337 to the total central generation scenario costs.

6.9 Open-Space Benefits from Distributed Generation

Distributed generation may also provide benefits to society, as illustrated by the following data on three Maryland counties, which are suburbs of the Washington, D.C. – Baltimore metropolitan area. Given the proximity to this urban area, preserved agriculture lands may provide substantial value to the citizenry, given the constraints on available land resources from developmental pressures. The data illustrates that

44 The parameter estimates for sq ft per kW is generated from the case study presented in the previous subsection entitled the Philadelphian Condominium.

45 The parameter estimates for sq ft per kW is the average between the industrial CHP turbine and the housing buildings with external CHP facility.

agricultural land, conserved through an agricultural easement, would be valued between $4,687 and $23,437 per acre.

Despite changes in urban and suburban development patterns, there have been efforts throughout the United States to preserve farmland. These activities include the development of governmental and non-profit initiatives to preserve these land resources by transferring farmland development rights, purchasing agricultural development rights, and purchasing agriculture conservation easements. Conservation easements are legal contracts that determine the ownership and level of development that is legally allowable for a specific unit of property. Lynch and Lovell (2002) estimate the supply of agricultural land easements paid to land owners in three rural counties in Maryland: Howard, Carroll, and Calvert. The prices predicted by the analysis include the opportunity cost of preservation and the non-market benefits of rural open space. The price estimates for the preserved farmland values are presented in Table 6.10.

Table 6.10. The Value of Conserved Agricultural Lands in Rural Maryland

Maryland County Name	Calvert	Carroll	Howard	Total
Mean Price Per Acre	$2,403	$1,165	$4,685	$2,631
Average Year of Sale	1990	1987	1989	1988
Mean Price Per Acre in 2006 Dollars[46]	$3,758	$1,981	$7,356	$4,352

Source: Lynch and Lovell 2002.

This research by Lynch and Lovell (2002) reveals that agricultural land easements are determined by the distance from the agricultural land to urban areas and its productivity potential. In regards to DG resources, this is relevant given that siting stand-alone DG facilities and central power sources could be affected by these spatial and land characteristics.

6.10 Land Use Case Studies

The estimated value of open space as explained in this section is used to assess the potential land use benefits associated with replacing central power facilities with distributed generation resources. Three case studies presented here – a condominium project in Philadelphia, a wastewater treatment plant in Portland, and a national park project on Santa Rosa Island – provide a context and focus for estimating land use benefits of DG.

The Philadelphian Condominium	Columbia Boulevard Wastewater Treatment Plant
The Philadelphian is a 1.4-million sq ft, upscale condominium building in downtown Philadelphia, Pennsylvania, adjacent to the Philadelphia Museum of Art. In 1989, the Philadelphian Owners' Association opted to install an on-site combined heat and power (CHP) plant for the 22-story, 776-unit building. The Philadelphian Owners' Association financed the project	The Columbia Boulevard Wastewater Treatment Plant is the largest water treatment facility in Oregon. Operated by the City of Portland, the plant treats an average of 80 to 90 million gallons of sewage per day. Byproducts of the water treatment process are bio-solids that are also treated. In the bio-solids processing, anaerobic digesters use the action of bacteria to break down solids and thus

46 Dollar figures adjusted to 2006 dollars using the average U.S. Gross Domestic Product Implicit Price Deflator over the previous 24 years, 1981 to 2005.

The Philadelphian Condominium	Columbia Boulevard Wastewater Treatment Plant
using a 15-year guaranteed energy savings contract with Cogeneration Partners of America. The association contracted with Eastern Power Corporation to operate the plant. The CHP system, which generates all the heating, cooling, water heating and most of the electrical power for the building, has resulted in about $300,000 yearly energy costs savings, a 25% reduction from previous years. The building must be conditioned 24 hours a day and have a constant supply of outside air for ventilation. The building's cooling load is about 1,500 tons, and its heating load is about 38,163 million British thermal units (Btu). Annual electricity consumption is about 10 million kWh, or 7.14 kWh per sq ft, coming primarily from resident plug load, the central plant pumping system, the cooling towers and the electric chillers. Load reaches a high of 1.1 million kWh in July and August. Summer peak demand is about 1,900 kW and winter peak demand is 1,200 kW.	produce a combustible gas composed primarily of methane and carbon dioxide. Following the adoption of a city climate change strategy, the plant was tasked with considering options for environmentally friendly uses of the produced anaerobic gas. While options were under consideration in 1995 and 1996, the plant experienced extended power outages. These outages forced shutdown of the control center, which provides communication to more than 100 pump stations throughout the community. During this time, the city consolidated billing among several facilities with its electricity provider, Portland General Electric. Because of the city's environmental commitment, it opted to return part of the resultant cost savings from the consolidation to the utility as a green power premium through which the utility would build 500 kW of wind energy capacity. In turn the utility returned the premium to the city to install a 200 kW fuel cell at the plant that would run on the anaerobic gas, helping to solve both the environmental problem associated with the gas and the need for backup power at the control center. The fuel cell system, which began operating in 1998, provides continuous power for the plant and waste heat for process heating requirements. The fuel cell plant consists of the ONSI PC 25C fuel cell with integrated fuel reforming. The raw digester gas is treated by the gas processing unit, which consists of a dual set of tanks containing activated carbon that absorbs hydrogen sulfide and halogens. An air-metering pump provides a small amount of air for proper operation of the carbon beds. The system is clean, producing virtually no NO_2. The total price of the fuel cell installation was $1.3 million.

Channel Islands National Park Photovoltaic Installation
Santa Rosa Island is part of the Channel Islands National Park. The 52,794 acre island is located off the Santa Barbara coast, 44 miles west of the park headquarters in Ventura, California. The park's employee housing facility is located in a remote island location, requiring an independent power system. As diesel was considered expensive and risky to transport to the island, the park selected two off-grid 6.4 kW photovoltaic systems to power the housing facility. These systems, installed in 1998, complemented four solar hot water systems previously installed in 1988.

Sources: U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy. *The Power to Choose, and Save: Residents of the Philadelphian High-Rise Condominium Cut Energy Costs by 25% with CHP; Columbia Boulevard Wastewater Treatment Plant – CHP Case Studies in the Pacific Northwest;* and *Channel Islands National Park PV installation: Million Solar Roofs Success Stories.*

The monetary benefit values presented in these three case studies are based on two variables: (1) land-use required by central power sources as well as by DG; and (2) dollar amounts representing the value of open space and ROW cost savings. Data available on preserved farmland is utilized for the per-acre monetary value estimates. The quantity of open-space estimates is generated from the difference between the land-use required for the average central power source (492.86 ha or 1,217.86 acres) and the land use required for DG. Information on the land estimates is provided in Table 6.11.

Table 6.11. Quantity of Land Resources Required by DG Case Study Projects

Case Study	DG Technology	Electricity Generation	Minimum Open-Space Estimates: Land Required for Case Study[47]	Maximum Open-Space Estimates
Philadelphian Condominium	CHP	1.55 MW	503 sq ft	1217.85 Acres
Portland Oregon Wastewater Treatment Plant	Fuel Cell	200 kW	200 sq ft	1217.83 Acres
Santa Rosa Island	Photovoltaic	12.8 kW	2,304 sq ft	1217.85 Acres

The open-space estimates in Table 6.11 can be described as the minimum and maximum quantity of land acreage that is *not used* by a central power source. The minimum open-space estimate is the land required for the DG project. The maximum open space estimate assumes that a single central power source would be constructed *for each* specific project.

The range of land use benefits for each DG facility is presented in Table 6.12.

Table 6.12. Land-Use Benefits for Three DG Facilities

Case Study	Lower-Limit Benefits	Upper-Limit Benefits	Land Use Benefits Per kW[48]
Philadelphian Condominium	$1.99	$6,374,718.03	$22,169.64
Portland Oregon Wastewater Treatment Plant	$0.71	$6,374,756.93	$2,853.54
Santa Rosa Island	$9.08	$6,374,501.70	$41.81

The lower-limit value in Table 6.12 is derived from the per-acre estimates observed by previous USDA CRP research (equivalent to $171 in 2006 dollars) and assumes minimum land required for the DG facilities. The upper-limit benefit is the maximum benefit to society of the DG project based on the price of land per acre, presented by Irwin (2002) (equivalent to $5,234 in 2006 dollars) and the maximum available acreage data presented in Table 6.11. Irwin (2002) has presented the greatest per-acre value of preserved agricultural lands. Land-Use Benefits per kW represent the dollar value comparisons between central power and DG land use requirements for each project. Each project creates land use savings, compared to the land required by central station projects, based on per-kW land use estimates.[49] The

47 Information in this table is developed using data on sq ft/kWh presented in Table 6.8, Land Use for Typical Distributed Energy Resource Facilities. Specifically for the Philadelphian Condominium, the parameter sq ft/kWh in Table 6.7 entitled Natural Gas Engine is used, which is equal to 0.325. On the other hand, for the Portland Oregon Wastewater Treatment Plant and Santa Rosa Island case studies, the parameters located in the columns entitled Fuel Cell and Building Integrated Photovoltaic Array are used, 0.9 and 0.

48 The land use estimates for this column utilizes information from Table 6.11, specifically for the Philadelphian Condominium and Portland Oregon Wastewater Treatment Plant. The sq ft/kWh for a central power facility is assumed to be 233.18 which is derived from Spitzley and Keoleian (2004). The sq ft/kWh for the Santa Rosa Island example is 180 which is calculated from data presented in Spitzley and Keoleian (2004)

49 Average sq ft/kW for a central power source estimated at 233.18.

amount of land saved at each site is equal to the difference between the land required by the DG project on a kW basis and the land required by a central power source on a kW basis.

The range of these savings can be significant and depends upon the area selected for construction of the central power source. When a central power source is developed in close proximity to an urban area, where open space is limited, the benefit of implementing DG resources may be more advantageous due to the higher value placed on open space in these regions. Alternatively, when a central power source is sited in a rural area, where open space is abundant, land use benefits from DG might not be as positive.

Rights-of-way costs may still be significant for electricity transmission firms. Data on per-acre ROW costs and total ROW costs are presented Table 6.13.

Table 6.13. Range of Saved Rights-of-Way Acquisition Costs for a Single Distributed Generation Facility

	Low-Limit Benefits	Upper-Limit Benefit	Median Benefit
Per-Acre ROW Costs	$1,780	$60,000	$30,890
Total ROW Costs (assuming 9.21 acres)	$16,394	$552,600	$284,497

Rights-of-way electricity transmission costs are shown to be between $1,780 and $60,000 per acre. The low-end figure of $1,780 per acre is based on Energy Information Administration data on the construction of transmission lines from a single central power source in 2003 (Energy Information Administration 2003). The upper range is representative of the per-acre costs observed in the natural gas, vehicular transportation, and electric power industries.

In summary, then, estimated rights-of-way savings could result from the three DG case studies, ranging from $16,394 to $552,600, depending on the location of the rights-of-way and the amount of assets located on the land. If multiplied throughout the economy, such savings could be significant, providing positive impacts to state and local governments as well as the utilities themselves.

6.11 Major Findings and Conclusions

Energy generation, transmission, and distribution has an obvious impact on land use, regardless of whether it is central station or distributed generation. Under certain circumstances, DG can have positive land use benefits, including smaller land mass requirements, savings on acquisition costs, rights-of-way, and land retention for open space, agriculture, or public benefits purposes. Distributed generation systems have land use impacts of their own, however, especially when they are built and operated separately – or outside – of the host building or facility. DG systems that are incorporated into buildings, in an engine room, on a rooftop, or immediately adjacent, result in a smaller land use footprint. Where land prices are high, such as in industrial or urban communities, the resulting land use savings from distributed generation might, indeed, be significant. In summary, DG may provide public value to society through savings of both the *amount* of land required for construction, transmission, and distribution, and the *value* of land left available for other uses.

Section 7. The Potential Benefits of Distributed Generation in Reducing Vulnerability of the Electric System to Terrorism and Providing Infrastructure Resilience

7.1 Summary and Overview

The United States electric power system is vast and complex. Thousands of miles of high-voltage cable serve millions of customers around the clock, 365 days per year. While the ready supply of electricity is often taken for granted, incidents such as the terrorist attacks on September 11, 2001, the Northeast Blackout of August 2003, and Hurricanes Katrina and Rita remind us how dependent we are on electricity and how fragile the grid can be. Water systems, pipelines, communications systems, transportation networks, emergency operations centers, and nearly every other category of critical infrastructure defined by the U.S. Department of Homeland Security (DHS) is in some way dependent on electricity. In this sense, electricity is the critical enabler of homeland security.

In addition to the vulnerability of critical infrastructure facilities resulting from their dependence on the primary electricity grid, these facilities most often rely on antiquated backup technologies as their sole source of electricity in an emergency—primarily diesel generators with limited staying power and only average power quality. If these backup generators prove incapable of meeting emergency power needs—as was the case during Hurricanes Katrina and Rita—the resilience of the entire network of critical infrastructure is in jeopardy at the very time when its resilience is most needed. Alternatively, if critical infrastructure facilities were to rely instead on primary and secondary power sources not exposed to these weaknesses, the entire system of critical infrastructure would be more resilient and thus more secure.

The Energy Sector-Specific Plan of the U.S. Department of Homeland Security's National Infrastructure Protection Plan (NIPP) notes that a healthy energy infrastructure is one of the defining characteristics of a modern global economy:

> "It provides the lifeblood for commerce and is critical for our telecommunications, transportation, food and water supply, banking and finance, manufacturing, and public health systems. Any prolonged interruption of the supply of basic energy—be it electricity, natural gas, or petroleum products—would do considerable harm to the U.S. economy and the American people."[50]

This section discusses 15 of 17 critical sectors of the U.S. economy, including as assessment of their vulnerability to terrorism and how DG can be a useful solution for reducing this vulnerability.

[50] Interim Sector-Specific Plan, Energy Sector for Critical Infrastructure Protection, As Input to the National Infrastructure Protection Plan, Department of Energy, Redacted Draft, September 3, 2004. This is an Official Use Only plan that is currently not available to the public.

7.2 The Vulnerability of the Electric Grid and the Importance of Resilience

Protecting the nation's electricity delivery system is a daunting task. The sheer size and extent of the system makes clear the difficulty of protecting it against both terrorism and natural disasters. Over 5,000 power plants (882 gigawatts of capacity produce 4,055 gigawatt-hours of electricity each year[51]), and approximately 100,000 transformers, 63,000 substations and 160,000 miles of high-voltage transmission lines continuously direct electricity to 138 million customers across the country.

As stated in the NIPP:

> "The key energy assurance challenges facing DOE are directly related to the energy sector's complexity, diversity of ownership, and importance to all other critical infrastructure sectors. . . . DOE as the coordinating energy sector organization is not resourced to oversee the infrastructure protection of an infrastructure resource base valued in the trillions of dollars and absolutely critical to the welfare of the nation."[52]

Energy sector stakeholders—both public and private—realize that tough choices need to be made in deciding how best to invest scarce security dollars to manage risk in the sector. However, careful investments in the right protective and enabling technologies can secure the grid against destabilizing failure.

The Homeland Security Advisory Council's Critical Infrastructure Task Force recently recommended that the concept of "critical infrastructure resilience" (CIR) replace "critical infrastructure protection" (CIP) as the top-level strategic objective of the nation's critical infrastructure security efforts (Homeland Security Advisory Council 2006).[53] The Council defines resiliency as "the capability of a system to maintain its functions and structure in the face of internal and external change and to degrade gracefully when it must." In other words, resilient infrastructure systems will be less likely to collapse in the face of natural or manmade disruptions and will limit damage when disruptions do manage to inhibit the full functionality of the system.

With critical infrastructure security focused on the concept of system resilience, rather than protection, the task of ensuring the nation's infrastructure becomes more manageable and measurable:

> "Critical Infrastructure Resilience is not a replacement for CIP, but rather an integrating objective designed to foster systems-level investment strategies. Adoption of CIR as the goal provides a readily quantifiable objective—identifying the time required to restore full functionality (Homeland Security Advisory Council 2006)."

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51 Data for 2005 from the Energy Information Administration, accessed at http://www.eia.doe.gov/cneaf/electricity/epa/epates.html

52 *Ibid* at 35 and 56; for a review of the many challenges facing security stakeholders in the sector, see *ibid* at 35-36, 56-57, 75-76, and 96-98.

53 The Homeland Security Council is a high-level council comprised of leaders from state and local government, first responder communities, the private sector, and academia, which advises the Secretary on Homeland Security issues.

7.3 The Benefits of Distributed Generation Technology and Systems in Supplying Emergency Power

To address the vulnerabilities of the electric system to intentional disruptions, particularly those perpetrated by organized acts of terror, and to improve grid resilience, the National Research Council (NRC) of the National Academy of Sciences (NAS) recently recommended that "technology should be developed for an intelligent, adaptive power grid that combines a threat warning system with a distributed intelligent-agent system (NRC 2002)." Distributed generation can play an important role in such a system. In fact, the NRC points out:

> "The trend over time has been to build large, remote generating plants, which require large, complex transmission systems. Today there is a growing interest in distributed generation – generators of a more modest size in close proximity to load centers. This trend may lead to a more flexible grid in which islanding to maintain key loads are easier to achieve. Improved security from distributed generation should be credited when planning the future of the grid (NRC 2002)."

DG can improve resilience through its reliance on larger numbers of smaller and more geographically disperse power plants, rather than large, central station power plants and bulk-power transmission facilities. Although larger numbers of smaller-scale power plants increases the number of targets for intentional attack, they reduce the number of customers who might potentially be affected. Electricity consumers are less vulnerable to supply disruptions when they have the ability to "island" themselves and thus to protect segments of the grid, particularly in critical infrastructure facilities such as fire and safety buildings, telecommunications systems, hospitals, and natural gas and oil delivery stations.

A simulated terrorist attack on California's electric grid, which included a 25% reduction in power supplies, showed that recovery time would be about two weeks, at a direct cost to California's economy of almost $11 billion. Much of these costs would have resulted from lost manufacturing output, and wholesale and retail trades. Greater DG by the electric utilities that serve these sectors, or by the sectors themselves, could lessen these economic impacts (ICF Consulting 2003).

In fact, research has shown that larger numbers of DG systems result in "potentially significant reliability advantages to increasing the amount of distributed generation in the system (Zerriffi 2004)."

7.4 Distributed Generation as a Means to Reduce Vulnerability and Improve Critical Infrastructure Resilience

Opportunities for using DG vary in each sector, but most of the sectors are potentially appropriate for adopting on-site electricity generation, using one or more prime movers.

Emergency Services

The emergency services sector includes:

- emergency management
- emergency medical services
- fire and hazardous materials

- law enforcement
- search and rescue

Emergency operations centers, 911 call centers, police and fire stations, and their communications equipment all rely on electricity. Loss of power at these critical locations can lead to increased casualties on the part of both the initial victims of the emergency situation, as well as the emergency responders themselves.

Distributed generation could be indispensable in ensuring that emergency responders can communicate critical information when it is most needed. Microturbines, reciprocating engines, fuel cells, or photovoltaics can provide power to emergency operations centers, call centers, communications equipment, and police and fire stations. For example, during the Northeast Blackout of August 2003, millions of New Yorkers were left in the dark. However, the Central Park Police Station in New York City maintained crucial operations during a dangerous situation by virtue of a single 200 kW Phosphoric Acid Fuel Cell. This fuel cell provided full electricity and air conditioning to the building, allowing officers there to respond to quickly, safely, and effectively in the crisis situation.

In 1995 and again in 2003, wildfires destroyed transmission lines that supply power to portions of Utah, leaving thousands of customers without power. However, Heber Light and Power (Heber, Utah) was able to supply power to all of its customers, including municipal and county fire, rescue, and police operations, through distributed generation (approximately 20 MW, provided by 14 dual-fuel reciprocating engines). In Heber, law enforcement, fire, and rescue services were able to maintain full functionality during a time when their services were most in need, and, at least one hospital maintained normal operations.[54] Furthermore, clean water continued to flow to some 16,000 customers of a district water and sewer consortium. This was made possible by DG.

Public Health and Healthcare

The Public Health and Healthcare Sector encompasses all state and local health departments, hospitals, health clinics, mental health facilities, nursing homes, blood-supply facilities, laboratories, mortuaries, medical and pharmaceutical stockpiles, and supporting personnel. This includes such institutions as the Centers for Disease Control and Prevention, the National Institutes of Health, and the Strategic National Stockpile.

This sector requires electricity to facilitate all services to hospitals, disease-testing centers, and other healthcare facilities, including power, lighting, heat, chilled water, and air conditioning.

The storage of vaccines and donated blood requires refrigeration, and laboratories and disease-testing centers use electricity to carry out routine activities such as clinical tests and research. Electricity is also required by medical data networks.

While a certain amount of on-site generation is required by law to maintain "critical" loads in specified healthcare facilities (especially hospitals), there is room for these facilities to make greater use of CHP capacities provided by large turbines and hybrid power systems in covering all the load, and thus ensuring the continuation of "normal" operations. Fuel cells and microturbines could also provide electricity for refrigeration that is required for vaccine storage.

[54] Telephone conversation with Craig Broussard, Heber Light and Power, March 1, 2006.

Mississippi Baptist Medical Center (MBMC) in Jackson, Mississippi, is a 624-bed facility and maintains a 3.2 MW gas turbine CHP system. The steam generated by the system is used for hot water, sterilization, and adsorption chillers. As a result of Hurricane Katrina, the grid was down for some 52 hours. During this time, the CHP system at Baptist Hospital ran islanded and provided power, hot water, and air conditioning. It was the only hospital in the region to continue at virtually 100% operation; the independence provided by the CHP system allowed MBMC to proceed relatively unaffected. The staff at MBMC was able to assist in the disaster relief by taking in patients from the region, including a group from Biloxi Regional Medical Center. MBMC was also able to provide cancer treatments for approximately 46 cancer patients who were displaced by the disaster, and the dining rooms at the medical center were turned into child day care centers for children affected by the hurricane (Chamra and Weathers 2006).

Similarly, Presbyterian Homes, an assisted living and nursing care facility in Evanston, Illinois, has installed a 2.4 MW combined heat and power (CHP) plant to avoid another situation like the one that occurred in 1998, when an ice storm knocked out both utility feeds to the facility, resulting in over 600 elderly residents being left without heat (and power) for some nine hours (Midwest CHP Application Center 2006).

Drinking Water and Wastewater Treatment

The drinking water and wastewater treatment sector involves some 160,000 public water systems in the United States and over 16,000 publicly owned wastewater treatment works. Eighty-four percent of the national populace receives its water from a public water system. Electricity is necessary to automate wastewater treatment plants, and is also important for the pumping and filtration of water. More than any other resource in any sector discussed here, water is required by all humans for survival. A power outage could result in the inability to process wastewater, a loss of pressure in pumps that would result in unclean drinking water, as well as the potential inability to deliver potable water. The Britannia Water Treatment Plant in Ottawa, Canada, maintained normal operations with no interruptions in both the Northeast Blackout of August 2003 and the 1998 ice storm. Its capacity during the blackout consisted of one 3.5 MW gas reciprocating engine, one 1.5 MW diesel reciprocating engine, one 500 kW "essential services" generator, and two 2.0MW direct drive diesel pumps.[55]

Food and Agriculture

The food and agriculture sector accounts for about 20% of the nation's economic activity. The assets in this sector are mostly privately owned, and cover agricultural production from pre-harvest through post-production and national forest lands, the animal feed industry, and food facilities. The firms, farms, and facilities that are involved in agricultural production in all of its phases make extensive use of electricity to harvest, produce, and process these products. Some of the facilities that rely on electricity include grain storage and milling, aquaculture, food and beverage processing, refrigerated warehouses, distribution facilities, and grocery stores.

Loss of power in this sector would prevent firms and facilities from processing agricultural products for consumption, with potentially large product loss. For example, a loss of power to the aquaculture industry could mean a catastrophic loss of fish intended for human consumption. The inability to

[55] Telephone conversation with John Hamilton, Britannia Water, April 2, 2006.

produce, process and deliver food would result in a scramble for resources, reliving instances in humanity's past, where drought or political actions have resulted in starvation, chaos, and refugees.

Distributed generation has distinct applications in this sector, especially in industrial applications that process agricultural products for consumption. Large factories and warehouses could make use of turbines and CHP, in addition to fuel cells and locally appropriate renewable resources to continue their operations even in the face of a regional blackout.

Entenmann's Bakery in Bayshore, New York, experienced no interruption in its operations during the Northeast Blackout of August 2003. Their 5.1 MW onsite CHP system consists of four reciprocating engines that run primarily on natural gas. No product was lost and no expensive cleanup and restarting was required (Energy and Environmental Analysis, Inc. 2004b).

Telecommunications

The telecommunications sector encompasses many electricity-dependent systems, including all wire communications (among them the public switched telephone network or PSTN), cable and enterprise networks, wireless communications (including cellular telephones and radio), satellite communications, Public Safety Answering Points and 911 Services.

The high-tech facilities associated with this sector have high load factors, and concentrated electronics require large cooling loads. Cellular telephone towers and radio services rely on electricity to provide wireless communications. Terrestrial satellite components use electricity to ensure internet data and video services, among others. Emergency services, specifically 911, need electricity in the interest of public safety and timely emergency response. A loss of electricity in this sector would have far-reaching effects. Perhaps most critically, the disabling of 911 and Public Safety Answering Points would mean that individuals in need of emergency services could not make those needs known and therefore, could not be rescued or treated.

Communications could be especially important in mitigating the damage of a terrorist attack; without the ability for emergency responders/law enforcement to communicate safety information, more damage could be done, and more disorder could ensue. Loss of terrestrial satellite and wireless capabilities would mean the crippling of cellular phone services, radio communications, and Internet. In short, a loss of power in this sector could limit or preclude the ability to communicate with others remotely.

Distributed generation components and systems have already proven useful in this sector, but certainly there is room for expanded reliance. Cellular phone towers, terrestrial satellite equipment, PSTN and other networks, as well as radio services, all have the potential to make use of on-site generation, including photovoltaics, fuel cells and microturbines, to ensure that services are not interrupted. In both Kiln and Pearlington, Mississippi, DE equipment ensured the operation of critical telecommunications services in the aftermath of Hurricane Katrina. In these cases, generation took the form of solar photovoltaic that was provided on a portable trailer by the Florida Solar Energy Center.

In Kiln, the solar unit provided power to a radio studio for three weeks. This studio was responsible for broadcasting critical announcements from an emergency operations center (EOC). Such announcements included critical guidance for local citizens on where and how to seek help, food, shelter, and in general how to proceed in the face of the disaster.

In Pearlington, solar power ensured that the local point of distribution (POD) and shelter could communicate with the Kiln EOC via Ham radio.[56]

Additionally, Verizon Wireless maintains a central office in Garden City, New York, which requires significant electricity for cooling purposes. Most of its 2.7 MW load is now covered by a combination of a dual-fuel reciprocating engine, two diesel engines, and seven base-loaded fuel cells. The engines and fuel cells are the primary source of electricity for the computerized call-switching system. Absorption chillers are connected to existing chilled water and condensing systems and the heat recovery steam generator supplements two boilers in the boiler room for space heating purposes. This CHP system has been operational since June 2005 (U.S. Department of Energy, Office of Energy Efficiency and Renewable Energy, 2005).

Information Technology

The information technology (IT) sector encompasses all data centers and their hardware, including servers of all kinds, which store data, and enable Internet services and enterprise computing, in addition to other applications. This sector requires uninterruptible power, especially to maintain large volumes of critical data that business and industry depend on. A loss of power to the IT sector could have profound effects, especially if it precludes the use of the Web during a disaster, or results in the loss of data, or other computer services. Today's society is so reliant on IT-related services, their loss would prevent a number of everyday businesses practices from taking place. "[For] Commercial, industrial, government and military buildings with computers and Internet – even power interruptions that last for a fraction of a second can be economically devastating (Hinrichs et al. 2005)."

Distributed generation systems can serve as a power source for all industrial applications that produce hardware, software, and IT services, and for Internet service providers. Additionally, technology such as fuel cells can be used in data centers to power servers and other equipment that maintain data, networks, Web services, and more, with combined heat and power capabilities to provide for the cooling needed in data centers. Millions of dollars have already been invested by data center owners and application service providers to ensure that these resources and the information they house are redundant. One such provider, American Power Conversion Corporation, currently outfits data centers with proton exchange membrane (PEM) fuel cells, available in 10 kW modules.

Transportation Systems

The transportations systems sector ensures the movement of people and goods both within the country and to locations overseas. Its six sub-sectors (or modes) are aviation, highway, maritime, mass transit, pipeline systems, and rail. Perhaps most obviously, electricity is necessary to maintain the infrastructure that administers and facilitates the flow of traffic on highways and roadways (including stop lights, message boards, and other traffic signals). Fueling stations also require electricity to operate, and electricity is essential to many kinds of mass transit and rail operations, as well as air traffic and maritime control/tracking systems.

Pipeline systems also use electricity to ensure the transport of some liquid or gaseous products (oil, propane, natural gas, and chemicals). One major danger associated with a loss of power in this sector is

[56] Telephone conversation with Bill Young, Florida Solar Energy Center, February 7, 2006.

the potential inability to administer, govern, direct, or otherwise control the flow of traffic, whether on land, in the air, or on the ocean. The absence of infrastructure to facilitate automobile, rail, or air traffic, for example, could have a number of dire consequences, ranging from gridlock to chaos to catastrophic loss-of-life events. The disabling of main transportation hubs could have far-reaching effects in terms of air and rail travel. Critical nodes such as bridges, tunnels, and interstate access points would need to stay functioning in a disaster to allow people to flee the affected area. Other effects of a loss of power would include the inability to operate refueling stations and power oil refineries.

Distributed generation currently is an important element of reliable air traffic control operations, even during local or regional power outages. The supporting infrastructure (rail switching, traffic signals, etc.) for rail, highway, and roadway traffic could make greater use of on-site generation. More solar power capacity could be installed to ensure the continued operation of traffic signals and electronic road signs.

During the Northeast Blackout of August 2003, the Rochester International Airport in Rochester, New York, relied on a 750 kW natural gas-fired synchronous generator with full engine and exhaust heat recovery to maintain all air traffic control capabilities and other critical loads. Waste heat generated by the engine is recovered and used for both building heat and operation of a 300-ton hot water absorption chiller.[57]

Commercial Nuclear Reactors, Materials and Waste

The commercial nuclear reactors, materials and waste sector includes the nation's 104 commercial nuclear reactors licensed to operate in 31 states—20% of the nation's electrical generating capacity. It also includes nuclear reactors used for research, testing, and training; nuclear materials used in medical, industrial, and academic settings; nuclear fuel fabrication facilities; the decommissioning of reactors; and the transportation, storage, and disposal of nuclear materials and waste.

Nuclear plants use electricity for regulation and control of energy production, as well as for emergency warning systems. A loss of power in this sector could result in the complete shutdown of a nuclear power plant, which could in turn disrupt the production of significant amounts of electricity, potentially affecting a large number of households and businesses. A worst-case scenario power loss could contribute to the failure and/or malfunction of a reactor or cooling system, which has the potential for a nuclear event, with any number of associated radiation effects.

The U.S. Nuclear Regulatory Commission reports that, in the wake of the Northeast Blackout of August 2003, "on-site power sources such as backup diesel generators provided power to operate essential safety systems" at the handful of nuclear power plants affected by the outage (U.S. Nuclear Regulatory Commission 2006). In July 2005, the Vermont Yankee Generating Station experienced a broken electrical insulator outside the reactor. This caused the plant to automatically shut down. While grid power was restored relatively quickly, the plant's 4kVa emergency diesel generators started automatically when incoming voltage degraded. According to Gonyeau (2005), "every nuclear power plant has at least 2 diesel generators that provide emergency electrical power in the event that all offsite electrical power is lost. The diesel generators are typically tested 1-2 times per month; they are run for 1-4 hours at each test. Several times per year the diesels may be run for up to 24 hours to ensure that the equipment functions during a loss of offsite power."

[57] Scott Smith, New York State Energy Research and Development Authority, personal interview, April 2006.

Energy Production, Refining, Storage and Distribution

The energy production, refining, storage and distribution sector encompasses three key segments: electricity, petroleum, and natural gas. The electricity sector involves some 5,000 power plants with 905 GW of generating capacity. The petroleum segment includes the exploration, production, storage, transport, and refinement of crude oil; in fact, there are 152 petroleum refineries in the United States. The natural gas segment encompasses production, piping, storage, and distribution, as well as the capacity to receive liquefied natural gas (LNG) from foreign vessels. Natural gas currently is processed at 726 different plants. The production and refinement of crude oil, the production and distribution of natural gas, as well as the automation of power plants all require electricity.

For example, in oil production, electricity is needed for oil-pumping units, for the pumps that inject steam into the wells, and for water-disposal pumps. A loss of power in this sector would mean, among other problems, the inability of energy carriers to reach their end users and an inability to process various energy sources for consumption. This could result in considerable chaos, as most of society is dependent on gasoline and diesel for automobiles, and there would certainly be a race among citizens to secure as much fuel as possible. Distributed generation systems could provide the power that is needed by refineries, in addition to facilities that store petroleum and natural gas.

One oil production company has taken steps to assure supply. Plains Exploration & Production Company maintains a wellfield near San Luis Obispo, California. The company produces 1,700 barrels of oil per day. Recently it installed a natural gas turbine (cogeneration) that now provides nearly 70% of its load of 1.8 MW. The system was built with earthquake preparedness in mind, and on December 22, 2003, this feature was tested: A magnitude 6.4 earthquake occurred, with the epicenter located 30 miles from the oil field. Designed for Seismic Zone 4 (the most rigorous classification for protection from earthquakes under the 1994 Uniform Building Code and subsequent codes based on it), the gas turbine and supporting infrastructure ensured uninterrupted wellfield operations during this event (Leposky 2004).

The city of Russell, Kansas, in partnership with U.S. Energy Partners, LLC (which maintain a 40-million-gallon-per-year ethanol production facility) has installed a 15-MW CHP system (two natural gas turbines at 7.5MW each). The CHP system provides the total electric requirements of the ethanol plant (3 MW), has the capability of providing up to 65% of the steam requirements of the ethanol production process, and provides 12 MW of electric power to service the citizens of Russell, Kansas and surrounding area (Midwest CHP Application Center 2006).

Chemical

The chemical sector encompasses four main segments, based on the end product produced:

- basic chemicals
- specialty chemicals
- life sciences
- consumer products.

There are several hundred thousand chemical facilities in the United States, ranging from production facilities to hardware stores. This sector makes use of electricity to process and store chemicals and hazardous materials.

A loss of power in this sector not only would mean a shortage in the supply of chemicals that our society depends on, but a potentially increased vulnerability of toxic substances to tampering or release. These approximately 140 chemicals have the potential to pose great risk to human health and the environment if they are not secured. Many chemical and metallurgical facilities do not have adequate backup power resources, so processes that rely on electricity can be interrupted within minutes of grid loss (Hinrichs et al. 2005).

On-site energy generation from large turbines with CHP could provide the total load(s) needed by the (approximately 15,000) industrial facilities that produce, distribute, or store chemicals.

During the Northeast Blackout of August 2003, Eastman Kodak in Rochester, New York, made use of its CHP system to ensure that no product was lost and no costly cleanup was needed as a result of the grid failure. Its CHP system consists of 12 steam turbines that use coal as a primary fuel, and has a capacity of 196 MW. Its thermal output is in the form of steam (Energy and Environmental Analysis, Inc. 2004b).

Defense Industrial Base

The defense industrial base sector provides defense-related products and services that are essential to mobilize, deploy, and sustain military operations. It includes over 100,000 companies and their subcontractors. This sector relies on a large industrial base that requires a significant electrical load to produce defense-related products and services. Loss of power in this sector would weaken the military capability of the United States, including the ability to defend its home soil and fight wars abroad. In short, a loss of power in this sector would leave the country particularly vulnerable to attack, and weaken its domestic and international military presence.

The Portsmouth Naval Shipyard in New Hampshire is primarily responsible for the overhaul, repair, modernization, and refueling of Los Angeles Class nuclear-powered submarines. The facility maintains one 5.2 MW natural gas engine and one 5.5 MW dual fuel engine, both equipped with heat recovery boilers for cogeneration. Furthermore, the shipyard houses two diesel engines (2 MW each) for backup electricity, in addition to numerous smaller diesel generators. The shipyard can cover its entire load with this capacity, but may at times receive power from, or export power to, the grid (the latter takes places to "prop up" the grid during times of congestion or system stress). The shipyard can, and on occasion has completely separated from the grid without affecting normal operations. These instances include September 11, 2001, as well as ice storms that have beset the region in the last several years.[58]

Banking and Finance

The banking and finance sector is a large and diverse sector that includes all banks, primarily federal and state-chartered depository institutions. Through the offering of financial products, financial services firms do the following:

- allow customers to deposit funds and make payments
- provide credit and liquidity
- allow customers to invest funds
- transfer financial risks between customers.

[58] Sharon Parshley, Energy Manager, Portsmouth Naval Shipyard, telephone conversation, April 25, 2006.

A loss of electricity would have powerful implications for this sector, which is the backbone of the world economy. It could make customers unable to obtain cash, either from banks or from ATMs. It could also disable the stock market and disallow the sale and trade of investment products. The risk-transfer community could also be affected, meaning, for example, the inability of customers to file insurance claims and recoup costs.

The longer financial markets and banking services are disabled, the worse the economic impact of any crisis situation would be; thus, DE would ensure that the economic cost — and general chaos, disruption, and dislocation of a disaster — would be lower than otherwise. Microturbines, fuel cells and photovoltaic systems can provide electricity to automated teller machines (ATMs), or to provide critical and emergency power to physical banks, financial trading networks, risk-transfer organizations, securities firms, and other financial institutions. Total loads could be provided by larger engines and turbines.

In the wake of the 1998 ice storm that affected parts of Québec, Ontario, and the northeastern United States, Corporation de Chauffage Urbain de Montréal (CCUM) supplied 100% of the load for several large office buildings that included the National Bank of Canada and Sun Life Insurance. This was made possible with a 1 MW steam turbine, four boilers, and two 500 kW diesel reciprocating engines.[59]

<u>**Commercial Facilities**</u>

The commercial facilities sector is a broad sector, and includes hotels, commercial office buildings, public institutions, convention centers and stadiums, theme parks, schools, colleges, apartment buildings, restaurants, and shopping centers. This sector makes extensive use of electricity to provide human comfort (heating, air conditioning, ventilation) in addition to powering the appliances that society uses on a daily basis. Furthermore, electricity is used extensively in this sector for the preparation and cooking of food.

Loss of power in this sector would have immediate effects on a large number of people (including the probability of panic), and would be associated with the inability to provide human comfort, lighting, and operation of appliances on which we depend. In such events, maintaining large office buildings or other facilities such as stadiums or shopping malls with power would mitigate chaos by maintaining a level of public confidence. Loss of electricity additionally results in the spoilage of refrigerated and frozen food.

A number of technologies are appropriate to sustain this sector with heating, ventilation, air conditioning, refrigeration, lighting, and the operation of electrical appliances, including renewable energy of all types, large engines and microturbines, fuel cells, and hybrid systems.

In 1998, an ice storm affected parts of Québec, Ontario, and the northeastern United States. In downtown Montréal, Corporation de Chauffage Urbain de Montréal (CCUM) supplied a group of high-rise office buildings with electricity and steam via its district energy system. CCUM operates a 1 MW steam turbine, four boilers, and two 500 kW diesel engines. This generation capacity was enough to support 100% of the load for all 20 office buildings that CCUM services, a total of 14 million square feet, and enabled these facilities to operate independent of the grid for 13 days, until utility service was restored.[60]

59 Mike Murphy, Corporation de Chauffage Urbain de Montréal, telephone conversation, January 25, 2006.

60 Mike Murphy, Corporation de Chauffage Urbain de Montréal, telephone conversation, January 25, 2006

Postal and Shipping

The postal and shipping sector is responsible for the movement of hundreds of millions of messages, products, and financial transactions each day. This sector uses electricity to process millions of letters, as well as small- and medium-sized packages each day. In addition to distribution and sorting facilities, electricity is also needed at post offices throughout the country, in both rural and urban communities.

Distributed generation systems can provide direct electric and thermal energy for postal and shipping facilities. In fact, two large postal facilities in northern California have recently installed distributed generation systems, the San Francisco Processing & Distribution Center (P&DC) and Embarcadero Postal Center. The P&DC maintains a hybrid solar/fuel cell power plant with a 250-kW fuel cell and 285 kW in solar panels (Renewable Energy Access, 2006).

Government Facilities and Services

The government facilities and services sector includes facilities that are typically built, leased, or otherwise acquired to perform a specific department or agency mission at the federal, state, or local level. A facility can consist of one building or multiple buildings on the same site. Power is necessary in this sector to provide services normally required by buildings: electricity, air conditioning, heating, chilled water, and ventilation. Power is also needed to facilitate government disbursement programs, including Social Security, Medicaid, and veterans' benefits.

A loss of power would render useless the facilities in which governmental departments and agencies operate. This would significantly affect the ability of all levels and areas of government to maintain order and provide administration. The ability of the government to disburse funds to recipients would be adversely affected, leaving many without money, and possibly result in desperation among those who are reliant on this money, including the elderly, the disabled, single mothers, and veterans. On-site generation such as that provided by natural gas turbines with CHP, in additional to fuel cells, geothermal energy, photovoltaics, and hybrid systems could be utilized to provide services normally required by buildings.

The Los Angeles Department of Water and Power headquarters in downtown Los Angeles, California, is powered by a 250 kW fuel cell. The organization's Main Street facility receives electricity from a second fuel cell with a capacity of 200 kW (University of Dayton Sustainability Club, 2006).

7.5 Major Findings and Conclusions

Recent examples from nearly every area of critical infrastructure as defined by DHS verify that DG is a viable means for reducing vulnerability to terrorism and improving the resilience of electrical infrastructure. This is based on actual cases in which DG continued to provide power to critical facilities during times of large-scale power disruptions and outages. These types of outages closely resemble the potential effects of a terrorist attack, one that could be directed at the grid and its components to maximize the loss of power delivery capability. A resilient grid can avert many types of losses, be they economic, material, or information, or losses of human life, health, safety, and communication. DG is one important tool that offers a solution for safeguarding against future losses, including those resulting from terrorist activity.

Section 8. Rate-Related Issues That May Impede the Expansion of Distributed Generation

8.1 Summary and Overview

In many states across the country grid-connected DG is subject to a variety of rate-related and other impediments that can ultimately hinder the installation of DG units. These impediments result from regulations and rate making practices that have been in place for many years. In the vast majority of instances these rate making practices are under the jurisdiction of the states. Recently, there have been activities in many states to address these impediments in order to make it easier for DG developers, customers, and interested utilities to install DG units. Subtitle E of the Energy Policy Act of 2005 contain several provisions which require the states to consider net metering, time-based rates, and interconnection of DG units. These provisions are expected to increase the pace of activity in the states to address rate-related issues that affect DG.

The most common rate-related impediments that affect DG owners and operators include the potential for lost revenue on the part of utilities, and practices such as standby charges, retail natural gas rates for wholesale applications, exit fees, and sell-back rates. There are several other rate-related issues which are somewhat less common; these include payments for locational marginal pricing, capacity payments, co-generation deferral rates, and remittance for line losses.

There are also several non-rate related impediments that affect the financial attractiveness of DG and these include interconnection charges, application and study fees, insurance and liability requirements, and untimely processing of interconnection requests.

8.2 Introduction to Utility Rates

Utility rates have the greatest impact on the practicality of DG because they affect the payback rate and time period for the DG investment. Unfortunately, a simple analysis of current utility rates and DG costs is not sufficient for payback analyses because utilities may have rates and charges specifically for DG that are not included in the customer's current rate. The potential magnitude of these impacts can vary substantially depending on the technology chosen, the size of the generator, charges for utility system studies, interconnection application fees, and specifics of the serving utility's rate structure.

For example, an analysis of standby charges in New York State (Energy Nexus Group and Pace Energy Project 2002) showed their material impact on project payback terms. For an 800-kW engine with combined heat and power (CHP), the simple economic payback ranged from less than 2 years with no standby charges, to 6 years with the utility's proposed standby charges. Other technologies showed similar impacts, with payback periods roughly doubling depending on standby charges alone.

Consider the siting of a CHP plant at a hospital in San Diego, California. For this hypothetical example the optimized size for the CHP plant is 1000 kW. The operating cost is estimated at 8¢/kWh. Off-peak rates (weekends and nights) are 7¢/kWh, which will not support operation. On-peak rates (7 a.m. to 9 p.m., Monday through Friday) are 18¢/kWh providing sufficient savings to support operation during this period. Without any rate- related impediments, the customer could expect an approximately 6-year simple payback (See Table 8.1). Typical barriers shown in Table 8.2 would increase the simple payback to 11.5 years, which discourages private investment. If these barriers were not sufficient to stop the project, many utilities are allowed to offer a subsidized rate. Table 8.3 shows the impact of lowering the rate to 15¢/kWh, which, by itself, would increase the simple payback to 8.1 years. In many states customers may attempt to leave the utility system to avoid standby, interconnect, and non-coincidental peak demand charges; however, utilities then charge an exit fee, the impact of which can be found in the last item of Table 8.3.

Table 8.1. No Direct Rate-Related Impediments

Size (kW)	Installed Equipment Cost $/kW	First Cost	Spark Spread ($/kW)	Operating Hours	Annual Savings	Simple Payback (yrs)
1000	$2,000	$2,000,000	$0.1	3500	$350,000	5.7

Source: Southern California Edison 2006.

Table 8.2. Tariff Impediments

Impediment Description	Barrier Cost	Change to Simple Payback Impact (yrs)
Standby Charge ($6/kW/mo)	-$72,000 annually	+1.5
Non-Coincidental Off Peak Demand Charge ($12.5/kw/mo)	-$127,000 annually	+3.3
Interconnect Charges	$300,000 upfront	+1.0
Total Impact		+5.8

Source: Southern California Edison 2006.

Table 8.3. Impact of Lowering Rate

Indirect Tariff Impediment	Project Financial Impact	Impact on Payback
Load Retention Rate	$245,000 annually	2.4
Exit Fee	$1,000,000 upfront	2.9

Source: Southern California Edison 2006.

Energy user and technical associations, and state and federal entities have attempted to address such impediments through user information, new technical standards, policy development, and outreach. A recent report by Johnson et al. (2005) consisted of a survey of state activities on DG including regulatory proceedings, tariffs, publications and interviews. This section provides an analysis of many of the issues raised in that report.

Investor-Owned Utilities, Public Utilities, and Restructured Markets

The electric utility industry consists of a large number and variety of entities. In general, there are generation companies (including utilities) that produce power, which is sold in wholesale power markets and delivered through high-voltage power lines to retail utilities. Retail utilities may own their own generation and transmission lines, but they always own local distribution lines to serve their retail customers. Most utilities purchase at least some power from wholesale power markets and many sell power through these markets. A small number of large power users (typically industry and federal agencies) purchase power directly from the wholesale power market, bypassing local utilities.

Retail utilities are organized following one of two models. The first is the typical corporation that is owned by stockholders and earns a profit on power sales, called "investor-owned" utilities (IOUs). The second is one of several forms of "publicly owned" utilities (POUs), including rural electric cooperatives and municipal utilities. IOUs are subject to rate regulation by state and federal regulators. POUs are mostly exempt from state regulation and are only subject to federal regulation of transmission rates and wholesale power sales. Despite the wave of market restructuring legislation that dominated the electric utility industry in the 1990s, the majority of utility customers in the United States today are still served by traditional state-regulated IOUs, municipal utilities, or rural cooperatives.

For states that have restructured from traditional state regulation, this section will address those tariff issues that remain under the control of regulators that can impact CHP and small power production (DG) facilities. In restructured states, generation prices are theoretically set by market competition. However, several restructured states have also developed interconnection procedures and *pro forma* agreements to reduce barriers to distributed generation systems. This includes states such as California, Michigan, New Jersey, New York, and Texas.

Principles of Rate Regulation

Rate classes—or groupings of customers—and the concept of ratemaking in general, developed as utilities and regulators recognized that various customer groups had similar load and service characteristics. As such, the utility could develop a cost of service (COS) allocation for each class and have a single rate or a few rates to cover each class. The cost of service for each class would cover expenses, overheads, and a fair rate of return (ROR) on equity to the utility. The revenue from rates in each class are expected to cover the costs of service for the class. If revenue from one class exceeds its COS, its use by another class would be called cross-subsidization of that class.

In general, rates, rules and requirements for customers within a customer class should be comparable. "Comparability" is a ratemaking term that means possessing the same characteristics or similar characteristics. If rates, rules, and procedures within a customer class are not comparable to all customers served under that class, either with or without DG, then rate-related issues may provide barriers or impediments to development and expansion of DG facilities.

In a typical ratemaking case, utility service is often divided into various COS components:

- **Customer.** The metering, billing, and other fixed costs associated with serving each type or class of customer.
- **Transmission.** Typically identified as costs for high-voltage lines and facilities and is handled as interstate commerce and regulated by the Federal Energy Regulatory Commission (FERC).
- **Distribution.** The costs of local delivery from network transmission substations to the customer location, typically at a lower voltage than the transmission network.

- **Generation.** The fixed costs of generators or capacity purchases that are pledged to make up overall supply of power and energy to the customer and the energy associated with the generation or purchase.

State regulation, by an elected or appointed board, sets allowable rates and other rules of utility service. In return, the utility can recover its cost of service—including prudently incurred business expenses—and a fair return allowed on equity. Caywood (1972) provides terminology often used for rate-related matters and regulation. Rate-related issues are bundled under the term "tariffs." Tariffs and parts of tariffs include the following:

- **Rates.** The prices for electricity.
- **Terms and Conditions of Service.** Rates plus provisions for billing and load conditions.
- **Rules and regulations.** The general practices the utility must observe.
- **Tariffs.** The term that encompasses all the schedules, rules, and regulation of the utility.

8.3 Rate Design

James Bonbright's 1961 text on the principles of utility regulation remains the comprehensive synthesis upon which regulators and courts rely when setting utility rates. They emerged from more than 60 years of regulatory case law at both the state and federal levels.[61] Paraphrased, Bonbright's principles are:

- Revenue-Related Objectives
  - Rates should yield the total revenue requirement.
  - Rates should provide predictable and stable revenues.
  - Rates themselves should be stable and predictable.
- Cost-Related Objectives
  - Rates should be set so as to promote economically efficient consumption (static efficiency).
  - Rates should reflect the present and future private and social costs and benefits of providing service (i.e., all internalities and externalities).
  - Rates should be apportioned fairly among customers and customer classes.
  - Undue discrimination should be avoided.
  - Rates should promote innovation in supply and demand (dynamic efficiency).
- Practical Considerations
  - Rates should be simple, certain, payable conveniently, understandable, acceptable to the public, and easily administered.
  - Rates should be, to the extent possible, free from controversies as to proper interpretation.

These principles are so well-understood and widely accepted that parties often advance them in support of their positions and regulatory agencies cite them as criteria to be met by their decisions.[62]

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61 Any experienced regulator or student of administrative law can easily cite the major court decisions on the principles of rate-setting, among them: *Smith v. Ames*, 169 U.S. 466 (1898); *Bluefield Waterworks & Improvement Co. v. Public Service Commission*, 262 U.S. 679 (1923); *federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Market Street R.R. Co. v. R.R. Commission of California*, 324 U.S. 548 (1945), and *Duquense Light Company v. Barasch*, 488 U.S. 299 (1989).

62 See, for example, *Fuels Research Council, Inc. v. Federal Power Commission*, 374 F.2d 842 (7th Cir. 1967) [invoking Bonbright in support of the proposition that capacity is built to meet peak demand] and VT Public Service Board Docket No. 5426, Order of July 22, 1992 [in which the Board accepts Bonbright's principles as guidelines in designing electric rates]. And even where not directly cited, the influence

Rate Elements and the Rationale Behind Them

To serve loads on demand, the electric system must have the capacity—generation, transmission, and distribution facilities—to serve peak loads, measured in kilowatts (kW) or megawatts (MW) in the instant of greatest demand for electricity. It is an expression of the power (and transport capability) that must be on hand if peak is to be met. It follows too that, if capable of meeting peak, the system is also capable of meeting lower-than-peak loads and that, at such times, some portion of its capacity will be idle. There are, of course, a variety of peak demands—a customer's individual peak, that of customers served by a particular distribution radial, substation, or transmission line, and that of a system in the aggregate—and these peaks do not necessarily occur at the same times (i.e., coincide).

Although planners design the system to meet peak, consumers want energy—that is, kWh delivered to their premises. It is energy that performs work, not capacity. Kilowatt-hours are created and delivered via operating capacity; they measure *the output* of capacity over time.[63]

Regulatory economists desire rates that reveal the economics of system planning and operations and they will argue that such rates achieve several objectives, especially the recovery of (and no more than) the legitimate costs of serving load from those whose loads cause those costs. This is a principle of both fairness and economic efficiency and, like most principles, it is more easily expressed in abstract than satisfied in practice. To the uninitiated, retail electric tariffs often appear quite complicated. While that judgment is not altogether unfair, it's nevertheless true that the essential price structures that they contain are fairly straightforward. There are three basic components of electricity rates: (1) periodic, fixed recurring fees, called customer charges, usually to recover the billing and metering costs that are not thought to vary with usage; (2) charges for units of capacity used or reserved to serve a customer's highest periodic demand; and (3) charges for units of energy delivered and consumed.

Demand charges are a means of allocating and recovering the costs of the capacity, measured in kilowatts, to serve the various peaks (system, individual, local network, etc.) to which a customer's usage contributes. They are often differentiated by type of capacity: generation, transmission, or distribution. They are intended to give the larger users strong incentives to manage their peak demand most efficiently, thus minimizing the investment in facilities that the utility must make on their behalf. Given that such facilities are typically long-lived and, in the short run, unvarying with demand for energy, capacity charges are often "ratcheted" by some multiplier (fraction) of customer peak demand for a specified number of months after the incurrence of that peak.[64] For example, in an annual demand ratchet rate

of Bonbright's synthesis (and those of other regulatory economists such as Alfred Kahn, whose two-volume *The Economics of Regulation* [John Wiley & Sons, Inc.: New York, 197o and 1971] has acquired a similar status) can be seen: see, for instance, *Re Central Maine Power Company*, 150 P.U.R. 4th 229 (Mine PUC 1994).

63 That the system must not only meet peak loads but also serve energy needs at all times has profound implications for the kinds of capacity that planners choose. Although this point is not immediately *à propos* to this paper, it is nevertheless appropriate to acknowledge it. If serving peak load were the system planner's *only* concern, he or she would rightly choose the least expensive capacity that could reliably do the job. However, it happens that there is a trade-off in generation between the costs of capacity and the costs of operation: low-cost capacity is marked by high operational cost and, conversely, high-cost capacity by low-cost energy. This is a general proposition and the plotted relationships aren't always neat and clean, but it explains why single-cycle gas turbines are among the most cost-effective of peaking resources, used very few hours in a year, and why hydro-electric, nuclear, coal, and gas combined-cycle units are built to serve base and intermediate loads. Thus, that portion of the capacity costs of units that exceeds the cost of the least-expensive (peaking) capacity can rightly be regarded as an energy cost, and treated as such for ratemaking purposes. See Edward Kahn, *Electric Utility Planning and Regulation*, American Council for an Energy Efficient Economy, Washington, DC, 1991.

64 A typical ratchet calls for the customer to be billed, in each of the eleven months following its peak demand, for either 80% of that peak demand or the peak in that month, whichever is greater. If a higher peak occurs, that new demand forms the basis of a new ratchet, which then extends for the following 11 months.

design, a customer with a peak load 10 MW in August will be charged for 10 MW of demand for the subsequent 12 months. If the demand exceeds 10 MW during that period, the ratchet is "reset" at the higher level and extended for another 12 months.

Ratchets are useful in rate design because they make revenues from demand charges more stable from month to month. Typically, the monthly demand charge with a ratchet rate design is lower than it would be otherwise as well. Therefore, ratchets have the effect of turning a fee that would otherwise vary with changes in demand into something more of a fixed charge that locks a customer into a minimum periodic payment for the duration of the ratchet. While there's certain logic behind ratchets—they link customer charges to the longer-term nature of the capacity obligations that they, the customers, cause—the logic is not absolute. Ratchets can constitute financial barriers for customers seeking alternative and more efficient means of meeting their energy needs.

Not all customers take service under tariffs that make use of demand charges. Rate designs depend on the levels and patterns of usage. For instance, the energy and capacity costs to serve lower-volume residential and commercial users are typically combined (through algebraic means) in unit energy charges ($/per kWh), as the expected benefits of customer response to differentiated demand and energy charges are generally not found to justify the costs of requisite metering and billing infrastructure (Kahn 1970; NARUC 1992).[65]

8.4 Rate-Related Impediments

The principles of ratemaking noted previously include allocation of costs to the customer or customer class that causes them. The installation of DG reduces utility power sales revenues, may cause the utility to incur costs for power purchases or losses on power sales for power expected to be used by the DG customer, reduces rate revenue from non-power related charges in rates (such as "wires" charges and general and administrative expenses included in a kWh rate), and so on. These costs would shift to other, non-DG customers if the utility did not recover them specifically from DG customers. This constitutes a subsidy of DG customers by other rate payers. By the same token, DG systems provide potential benefits to the utility and, by extension, other ratepayers, as noted elsewhere in this report. Accordingly, DG customers feel they are subsidizing the utility and other ratepayers. The primary rate-related impediments to DG noted by its developers include:

- lost utility sales revenue
- standby charges
- retail natural gas rates for wholesale applications
- exit fees and stranded costs
- sell back rates, including net metering, retail power prices/rate credits, and wholesale prices
- locational marginal price payments/credits
- capacity payments/credits
- co-generation deferral rates
- payments/credits for line losses.

65 Pilot projects in Florida and California have recent found that other rate designs for lower-volume customers, such as critical peak time-of-use pricing, can produce benefits from customer demand response that significantly outweigh the added infrastructure costs. See materials available on the website of the Mid-Atlantic Distributed Resources Initiative (MADRI) at http://www.energetics.com/MADRI/.

Table 8.4. Interconnection Procedures for New York, California, and Texas[66]

	New York	California	Texas
Step 1:	Initial communication	Utility sends application and requirements within 3 business days of contact by applicant.	Applicant completes application.
Step 2:	Inquiry review by utility to determine nature of project and applicant's information needs. Review and info sent to applicant by Utility w/in 3 business day of initial communication.	Applicant completes application. Normally, Utility shall acknowledge receipt of application and state whether it is complete within 10 business days of receipt of application and fee.	Upon receipt of completed application, Utility has 4 weeks (pre-certified equipment) to 6 weeks (non-pre-certified) to process application and sign inter-connection agreement.
Step 3:	Application filed. within 5 business days of receipt of application, Utility notifies applicant if application is complete.	Utility shall complete initial review for simplified interconnection within 10 days of determination that application is complete.	Pre-interconnection studies may extend deadline. E.g., Utility has up to 6 weeks additional study time for applicants in Network secondaries where aggregate DG is >25% of feeder loads.
Step 4	Utility conducts preliminary review and cost estimate for completing the CESIR (Coordinated Electrical System Interconnection Review). Utility sends outcome of review to applicant w/in 5 or 15 days of completion of Step 3. (15 days for 300kW<DG<2 MW	Utility notifies applicant if application doesn't pass initial review. Applicant pays fee and Utility performs supplemental review. Shall be completed w/in 20 business days of receipt of completed application and fees.	If substantial capital upgrades are necessary – Utility gives applicant estimate of cost and schedule. If applicant desires to proceed, Utility and applicant enter contract for upgrade. Commissioning test allowed within 2 weeks of upgrade completion.
Step 5	Applicant commits to completion of CESIR and applicable fees.	If significant modifications deemed necessary, both parties commit to additional study at applicant's expense.	Interconnection Agreement
Step 6:	Utility completes CESIR w/in 20 business day of receipt of info required in step 5; within 60 business days for DG>300 kW.	Parties enter into applicable agreement	Connection, testing and operation.
Step 7:	Applicant commits to construction of utility system modifications.	Construction, testing	
Step 8:	Project Construction Schedule as discussed with applicant in Step 6.	Interconnection	
Step 9:	Facility Testing < 15kW – test 2hrs	Reconciliation of costs within a "reasonable amount of time after interconnection."	
Step 10:	Interconnection		

66 Sources:

New York Public Service Commission 2005. "New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators 2 MW or Less Connected in Parallel with Utility Distribution Systems."

California Energy Commission 2005. California Distributed Energy Resource Guide – Rule 21.

Public Utility Commission of Texas 2002. "Distribution Generation Interconnection Manual."

Public Utility Commission of Texas. Substantive Rules Applicable to Electric Service Providers. Rule 25.211, available at http://www.puc.state.tx.us/rules/subrules/electric/25.211/25.211.pdf

Note that the rule and manual differ slightly. For example, the rule says "For a facility with pre-certified equipment, *interconnection shall take place* within four weeks of the utility's receipt of a completed interconnection application," whereas the manual, referencing the rule says, "Allowable Time from receipt of completed application to a *signed interconnection agreement*: 1) Systems using pre-certified equipment, 4 weeks (§25.211(m)(1))" [Emphasis added].

	New York	California	Texas
Step 11:	Final Acceptance & Cost Reconciliation within 60 days after interconnection	"Absent any extraordinary circumstances" qualifies many deadlines in rule.	

CESIR= Coordinated Electrical System Interconnection Review
DG= distributed generation

Loss of Utility Sales Revenue

Nature of the Impediment

Regulators establish rates based on specific load growth projections. If the load does not increase as projected, utilities may not recover sufficient revenue to cover the costs of capital investments. Demand side management tools such as energy efficiency (EE), CHP, and renewable energy (RE) can reduce demand such that utility load growth projections are not met. The problem can be made worse when coupled with certain rate design features. This loss of revenue is the basis for the utility argument that installation of EE, RE, DG technologies by customers can be unfavorable to the utility's overall financial health.

The question of net lost utility revenues is generally associated with programmatic delivery of end-use energy efficiency measures, but it is relevant to customer-sited generation too. Both energy efficiency and customer DG have the potential to cause net revenue loss for the host utility (Moskovitz 2000).[67] The disincentives to energy efficiency have been well understood for two decades, but have recently attracted new regulatory interest. The importance of revenue loss is a more potent disincentive to regulated utilities than it sounds for two reasons.

First, lost sales at some times are greater than at others. Lost sales during high-price, on-peak periods are more damaging than sales lost during other hours, when lower revenues from demand charges might cause an inflated net revenue reduction. In other words, the gap between the marginal cost of generating a kWh and the marginal revenue from its sale can be larger at some times than others, and larger than the gap between the overall average and marginal costs derived in ratemaking from the estimated revenue requirement. Since energy efficiency programs and DG installations will typically be designed to lower the customer bill as much as possible, they will inevitably be targeted to such high-cost periods.

Second, because of the capital intensive nature of electricity generation, lost revenues have an exaggerated effect on shareholder earnings. Note that in the short-run only the fuel cost is saved if a kWh is not generated. Capital and other fixed customer costs are still incurred. In other words, the cost of debt service is large and unchanging in the short-run, so lost revenues come largely directly from the company's bottom line. And of course, the converse is true. If sales exceed the expectations on which tariffs have been set, shareholders can benefit handsomely, a particular problem in jurisdictions where tariffs are not routinely revisited by regulators and any additional fuel costs are automatically recovered.

67 Moskovitz states "potential to cause" rather than "will cause" because the loss of net revenues is an empirical question. Its answer depends on a host of factors, including marginal power and delivery costs, customer growth, and overall revenue levels. In fact, in many instances, the savings to the utility that result from customer-sited resources result in net revenue gains. At its core, the question is not about revenues, but rather profits, and regulatory attention should be directed to methods by which utilities can be rewarded (or at least not penalized) for promoting societal-efficient outcomes.

This problem was long ago addressed by some states with the intention of making utilities indifferent to their level of sales, (i.e. not harmed by sales lost due to energy efficiency programs, a process generally known as "decoupling") (Moskovitz et al. 2002; Eto et al. 1994). These efforts were inspired by fuel cost adjustment mechanisms that are widespread in the industry as a means of preventing significant costs or benefits accruing to utilities as a result of unforeseen fuel price fluctuations. For example, the Electric Revenue Adjustment Mechanism was introduced in California in 1981, and in various forms has been in effect ever since. California is unusual in that rate cases follow a regular cycle, and are not just initiated by circumstances. Between rate cases, any revenue collections that deviate from projections used when tariffs were last set accrue in a balancing account. At the next rate case, the balance in this account is considered along with all other costs in setting rates for the next period. In other words, the utility is made whole and neither loses from sales below expectations or collects windfalls from high sales affecting its earnings, while it can still benefit from efficiency improvements (Marnay and Comnes 1990).

A recent publication entitled, *Regulatory Reform: Removing Disincentives to Utility Investment in Energy Efficiency,* points out that traditional ratemaking processes result in a number of disincentives to energy efficiency, among them (1) the loss of net revenues from sales, (2) the foregoing of other profit-making activities, and (3) regulatory restrictions on how utilities can recover program expense dollars. The first, loss of net sales revenue, clearly applies to the situation of customer-owned DG where local generation displaces customer purchases (*Regulatory Assistance Project Newsletter,* 2005). The second and third also appear to not apply to customer-owned DG, but could apply in the case of utility-sponsored programs in DG, where a utility might try to use small generation for system support and other benefits.

Relationship to Regulation, Tariffs, and Markets

State regulators have historically used price regulation for electric utility regulation. A cost-of-service investigation is the basis for setting prices. If the growth projections employed in setting rates are not met, utilities are not able to service the debt for capital improvements. Distributed generation and energy efficiency programs will reduce sales and may cause revenue projections to not be met. Since a loss in sales always causes a reduction in revenues, regulators and utilities need to look beyond revenues. In such situations, profits—the difference between revenues and costs—need to be examined. Distributed generation proponents argue that DG can be deployed in a way that reduces the new infrastructure costs to offset the reduced sales revenue, producing profits even while reducing total revenues.

Standby Charges

Nature of the Impediment

Standby charges (also referred to as backup service and often including maintenance and supplemental services) are charges that provide service to load utilities that would otherwise be served by an DG or CHP facility during a forced outage of the facility. In these standby rates, the utility continues to charge for generation and distribution services that the utility is ready to provide by "standing by." One typical approach to standby rates is to simply charge the rates to customers with DG (referred to as "partial requirements" customers) as are charged to like customers that do not have DG or CHP facilities ("full requirements" customers). Whether rates so designed and applied encourage or discourage the development of DG depends on the degree to which they impose disproportionate costs on the customer for facilities that are only rarely used. As a practical matter, this goes to the question of whether and how ratchets and non-usage-sensitive prices are imposed.

Utilities strongly argue that standby rates are needed to recover (1) the costs of grid investments (transmission and distribution) dedicated both wholly and in part to delivering power to customers with on-site generation costs, and (2) the costs of generation reserved to serve backup loads, in those jurisdictions where utilities still retain the obligation to the commodity electric service. Without standby charges of one sort or another, utilities argue that DG customers would pay less than their fair share of the costs incurred to serve them and other customers would be required to pay more than their fair share.

Distributed generation proponents offer several arguments in response. One is that, with respect to the generation capacity component, it is very unlikely that all of the local generation will be out of service at the same time, and that charges for standby service should be adjusted to reflect the diversity of DG on the system (that is, the very low probability that a significant share of the DG capacity will be inoperable at times of system peak). If no such adjustment is made, they argue, the utility will over-collect generation charges from DG facilities. In addition, DG proponents say that such standby charges are often discriminatory in that they impose charges on on-site facilities that are not applied to other equivalent load-reduction measures. Applying similar reasoning, DG proponents also argue that charges for delivery services should be based on the expected burden that demand for stand-by service will impose on the local facilities at times of local peak. This burden is not necessarily related to the size of the on-site generator, but rather to the probability of a certain amount of load occurring at particular times. Proponents also argue that standby rates should be adjusted to reflect the system benefits that distributed generation bestows—that is, improved reliability, deferred or avoided capital costs, and reduced environmental impacts. Lastly, all agree that the costs of facilities that are dedicated solely to a particular customer, whether partial requirements or full, should be recovered from that customer.

Relationship to Regulation, Tariffs and Markets

FERC has jurisdiction for interconnection of generating facilities to facilities included in an open-access tariff on file at FERC and has provided guidance (described below) for development of standby rates for them. For interconnection to state-regulated facilities, decisions on standby charges and rules for rates and tariffs are made in rate proceedings, where, in the resolution of specific issues, general policies often get hammered out. Approaches taken by several states are illustrative of the wide range of policies options available:

California. In 2001, the California Public Utilities Commission (CPUC) determined that rates for standby service should reflect the general nature of the service's costs, both usage- and non-usage-sensitive depending on cost element under consideration. Thus, California utilities charge DG customers a combination of monthly, ratcheted, per-kW capacity (or demand) charges and per-kWh fees for standby delivery and generation services, with provisions for supplemental and scheduled maintenance services as well. Standby customers are charged only for the capacity that they will need in the event of an outage of their on-site generation. The amount of that capacity can be designated by the customer and, though technical and contractual means ("physical assurance"), can be fixed as a maximum. In this way the customer is assured of paying no more for capacity than expected, and the utility is assured that it will not have to reserve additional capacity to serve an unexpected load. Distributed generation technologies that provide system or environmental benefits are, in recognition of those benefits, exempt from certain of the standby charges.

New York. Through a series of proceedings beginning in 1999, the New York Public Service Commission (NYPSC) developed rate and other regulatory policies for distributed resources. Out of the several processes emerged an approach to standby rates that has several intriguing aspects. First, standby rates are structured as a combination of fixed contract demand and as-used daily demand charges, and supplemental and maintenance services are not separately offered. Second, there are exemptions from, or phase-ins of, standby rates for specified technologies. Finally, there is special ratemaking treatment of revenue losses and gains associated with DG installations.

The NYPSC-issued guidelines state that standby rates "must reflect the cost of serving the standby customer," and "should provide neither a barrier nor an unwarranted incentive" to DG customers (New York Public Service Commission, Opinion No. 01-4, p. 11). While several stakeholders argued that benefits of DG, such as low emission and reduced line congestion should be considered in the standby rates, the NYPSC determined that public policy values or benefits to utilities from DG were extraneous to the development of standby delivery rates, and should be considered and applied, if appropriate, in the context of a utility's distribution planning process (New York Public Service Commission, Opinion No. 01-4, p. 27). Nevertheless, the NYPSC approved exemption and phase-in policies for small DG as well as renewable-energy-based DG, recognizing the benefits of those DG units (see description below). Further, the NYPSC later argued that "the economic 'benefits' of reduced or avoided utility delivery system costs are reflected in the standby rates" in the form of on-peak, as-used demand charges that reflect "the lower cost responsibility of standby customers for service classification coincident peak loads (New York Public Service Commission, Opinion No. 01-4, p. 11)."

New York's standby rates consist of a customer charge; a fixed, contract demand charge; and a variable, daily as-used (non-ratcheted) demand charge. The standby costs of delivery are recovered through two types of per-kW charges that are applied to the standby customer's demand "because the local costs of providing delivery service correlate with the size of the facilities needed to meet the generating customer's maximum demand for delivery service (New York Public Service Commission, Opinion No. 01-4, p. 12)." The first is the monthly, ratcheted contract demand charge, which recovers costs of local facilities that are "attributed exclusively or nearly exclusively to the customer involved (New York Public Service Commission, Opinion No. 01-4, p. 13)." The second is the daily as-used demand charge, for costs associated with "shared" facilities. It is applied to the customer's daily maximum metered demand that occurs during the utility's system peak periods.

The NYPSC does not differentiate, as others do, among types of standby service for partial requirements customers. The NYPSC denied a proposal for a split rate containing a "supplemental charge" and a "back-up charge" on the ground that "[t]he Guidelines provide cost-based delivery service rates that apply to the entire delivery service taken by a customer with an OSG [on-site generator] regardless of whether the OSG serves all or only a portion of that customer's load (New York Public Service Commission, Opinion No. 01-4, p. 21-22)."[68] The NYPSC also approved exemption and phase-in provisions for small customers (less than 50 kW) and for certain clean DG technologies.

Oregon. In 2004, the Oregon Public Utilities Commission approved a settlement on Portland General Electric Company's (PGE) tariffs for partial requirements customers. In the wake of the state's industry restructuring, Oregon's electric rates have been fully unbundled. Generation, transmission, and distribution services are all priced separately, and each generates revenues to cover its full embedded costs of service.

[68] New York Public Service Commission, Opinion No. 01-4, October 26, 2001, p. 21-22; New York Public Service Commission, Case 02-E-0780 et. al., *Order Establishing Electric Standby Rates,* July 29, 2003, p. 11; Attachment A, Joint Proposal by Orange & Rockland Utilities, Inc. and Consolidated Edison Company of New York, Inc. pp. 21-22.

Under the settlement, partial requirements customers, like all others, pay the full charges for distribution investments dedicated solely to them. These are recovered in a monthly per-kW demand charge assessed against what is called "facility capacity," which is the average of the two greatest non-zero monthly demands established during the 12-month period which includes and ends with the current billing month (the minimum amount of facility capacity is the customer's demand for grid—i.e., supplemental—power when the on-site generator is operating). The costs of shared distribution and transmission facilities are paid according to the probability of the average customer in the large non-residential class causing new investment. These too are recovered in monthly per-kW demand charges, but they differ in that they are assessed against the customer's on-peak monthly demand (which may or may not equal facility capacity). Peak hours are between 6:00 a.m. and 10:00 p.m. Monday through Saturday. The several transmission and distribution fees are essentially the same for partial as for full requirements customers (a one-penny difference in one rate element).

The PGE settlement is innovative in its treatment of stand-by generation capacity. The load served by the on-site generation is treated in the same manner as any other load on the system, which, under Oregon rules, is obligated to have (or contract for) its share of contingency reserves. The on-site generation is, in effect, both contributing to, and deriving benefits from, the system's overall reserve margin. The PGE tariff differentiates between two types of contingency reserves: the spinning reserves needed to instantaneously serve the load that is exposed when the on-site generation fails and the supplemental (or 10-minute) reserves that will come online shortly thereafter.

Under the new rates, the partial requirements customer pays or contracts for contingency reserves equal to 7.0% (3.5% each for spinning and supplemental reserves) of the "reserve capacity," i.e., either the nameplate capacity of the on-site unit or, in the alternative, of the amount of load it does not want to lose in case of an unscheduled outage (if the customer is able to shed load at the time its unit goes down, then it will be able to reduce the amount of contingency reserves it must carry).

To simplify the billing, the monthly demand fees for the two reserves are equal to 3.5% of their full cost. There are separate charges for the two types of reserves, but the charges are the same. All but the first 1,000 kW of reserved capacity required for customers with on-site generation is subject to the contingency reserve charges. The charges for the contingency reserves are multiplied by the reserve capacity. Mathematically the effect of this approach is the same as multiplying the full charges for the reserves by 3.5% of the needed capacity. If the customer so chooses, it may forego purchasing contingency reserves from PGE and, instead, purchase them from other providers in the market.

Actual energy received under unscheduled service is priced at an indexed hourly wholesale price, adjusted for wheeling, risk (to compensate PGE for any differences between the actual and indexed prices), and losses. Electric needs in excess of the demand served by the on-site generator are provided under the applicable full requirements tariff. Maintenance service is also available, for a maximum of 744 hours per year. It must be scheduled at least thirty days in advance; the timing and amount of the demand will determine whether incremental monthly as-used transmission and distribution charges will be incurred.

The effect of the PGE rate design is to give the partial requirements customer a strong financial incentive to operate its on-site generation, particularly during on-peak times. The energy charges and the charges for shared transmission and distribution facilities—significant portions of the cost of stand-by service—are avoidable through the reliable operation of the on-site generation. The costs of dedicated distribution facilities and contingency reserves are, in effect, access fees that cannot be avoided by either the full requirements or partial customer.[69] Table 8.5 describes the PGE standby rate structure.

The Oregon Public Utilities Commission recently approved a partial requirements tariff for PacifiCorp, the state's largest investor-owned utility. In its essential features, it mirrors that of PGE.

Minnesota. In 2004, the Minnesota Public Utility Commission (MNPUC) issued an order[70] on DG tariffs and policy. In an attachment to the order, the MNPUC set out guidelines for the regulatory treatment of customers with on-site generation. About the design of standby rates, it established the following policies:

Table 8.5. Portland General Electric Standby Rate Structure

Portland Energy Electric Schedule 75, Partial Requirements Service			
	Delivery Voltage		
	Secondary	Primary	Sub Transmission
Basic Monthly Charge			
Single-Phase Service	$20.00		
Three-Phase Service	$25.00	$150.00	$500.00
Transmission & Related Services			
Per kW of monthly Demand	$0.78	$0.78	$0.78
Distribution Charges			
The sum of the following, per month:			
Per kW of Facility Capacity	$2.27	$1.65	$0.32
Per kW of monthly Demand			
First 30 kW	$0.56	$1.90	$1.06
Over 30 kW	$1.90	$1.90	$1.06
Generation Contingency Reserves			
Spinning Reserves			
Per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
Supplemental Reserves			
Per kW of Reserved Capacity > 1,000 kW	$0.234	$0.234	$0.234
System Usage Charge			

69 Note that the method by which revenues to cover the costs of contingency reserves are collected from partial requirements customers differs from that for full. Whereas partial requirements customers pay monthly demand charges for contingency reserves, the cost of contingency reserves for full requirements customers is included in their energy prices.

70 Minnesota Public Utility Commission. In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Under Minnesota Laws 2001, Chapter 212. Docket no. E-999/CI-01-1023. St. Paul, 2001.

Portland Energy Electric Schedule 75, Partial Requirements Service			
	Delivery Voltage		
	Secondary	Primary	Sub Transmission
Per kWh	$0.00485	$0.00354	$0.00257
Energy Charge			
Baseline Energy	Per Schedule 83		
Scheduled Maintenance, max 744 hrs/ calendar year	Daily or Monthly Fixed, per Schedule 83		
Unscheduled	Dow Jones Mid-Columbia Hourly Firm Electricity Price Index, wheeling charges, a $0.003/kWh recovery charge, and a loss adjustment		

For Firm Service:[71]

Generation (capacity): The monthly reservation fees are equal to the percentage of the planned reserve margin of the utility times the applicable capacity rates. [The approach discounts the generation portion of the capacity charge by over 80% based on typical planning reserve margins.]

Transmission: Terms conditions and charges for transmission service are subject to the individual utilities' or MISO's Open Access Transmission Tariffs or their successors as approved by FERC.

Local Distribution: The monthly charges equal the monthly charge under the applicable distribution charge. There is no discount on the local distribution charge.

Several state commissions have used exemption of standby rates as a policy tool to encourage certain DG facilities.[72] These are a function of either size, where the small size of the generator renders non-cost-effective the administration of a separate standby tariff, or technology, in an effor to promote environmentally friendly systems (Johnson et al. 2005).

Exit Fees and Stranded Costs

Nature of the Impediment

Exit fees came to prominence during utility restructuring as competition and loss of customers became more common. Exit fees are paid by customers who, for whatever reason (the use of on-site generation or taking of service from a competitive provider), reduce or cease taking service from their local utilities. The rationale for these fees is to recover the costs of facilities (distribution, transmission, and generation) and contracts that utilities have incurred on behalf of these customers under their legal "obligation to serve." If the customer generates rather than purchases much of its energy, the utility is burdened with costs that it can no longer recover. Utilities argue that this puts a burden on the remaining customers (as a

71 Minnesota Public Utility Commission Docket No. E-999/CI-01-1023, Attachment 6, page 4.

72 Massachusetts and New York, for example.

whole or in the particular rate class) who will have to pay a greater share of costs as a consequence.[73] Distributed generation advocates argue against the application of exit fees, asserting that it is by no means clear that the decrease in revenues associated with one customer (or group of customers) won't be made up for by new sales to others,[74] and they say that such fees unfairly and negatively impact the economic viability of a project.

A number of states—including California, New York, and Pennsylvania—allow exit fees to be charged, but these are primarily associated with the recovery of stranded costs caused by the introduction of retail competition (see the following paragraph). In some cases, they are calculated on a case-by-case basis (Midwest Combined Heat and Power Application Center 2006). Opponents have argued persuasively that it would, in most instances, be unjust to levy them against customers who remain in the service territory when such fees are not, and have never been, charged against customers who simply depart the service territory.[75]

While exit fees are promoted on the grounds that they recover costs that would otherwise be stranded or, more likely, collected from other ratepayers, they are a different "stranded" cost than that which was the focus of much attention during the restructuring debate. In restructuring, "stranded cost" was the alleged difference (generally assumed to be negative) between the book and market values of regulated utilities' generation assets, i.e., those assets that were now going to be subject to competitive forces and whose costs were no longer to be recovered in regulated rates (which would now consist primarily of transmission and distribution costs).

As part of the overall settlement on restructuring in various states, the estimated book value of utilities' assets that were lost in market valuation and sale was typically recovered through a "competitive transition fee" paid by all consumers. As such fees are paid by all consumers in a state, they should not, by themselves, pose a barrier to DG deployment (except to the extent that their existence encourages customers to locate in jurisdictions that do not have such charges). Indeed, if the installation of on-site generation enables a customer to avoid stranded cost charges, they act more as an incentive than a hindrance.

Relationship to Regulation, Tariffs, and Markets

Exit fees and stranded costs recovery generally came under scrutiny with the utility restructuring that occurred in the late 1990s and early 2000s. In 1996, the FERC issued a ruling that utilities could recover 100% of their stranded costs if FERC's open transmission access rule allowed wholesale requirements customers to leave the system. States adopted their own approaches to the issue. Typically, rules were enacted to cover the loss of customers to alternative suppliers, usually for specific period of time. In several states, this loss of load was extended to the addition of customer generation where the customer provided much of his own supply. California, Illinois, Massachusetts, New York, Pennsylvania, and Texas all have or have had exit fees for local generation. Actual fees vary by state. Fees are often an

73 Note that this is true whenever a customer leaves the system and no other customer or sales replace the net lost revenues.

74 The issue is, strictly speaking, not one of gross revenue losses, but rather of net revenue losses and reductions in earnings. Reductions in sales are accompanied by a reduction in costs that must be accounted for in any calculation of financial impact on the utility.

75 Massachusetts, for instance, allows exit fees to be charged against DG applications that are greater than 60 kW. Renewable energy technologies and fuel cells are exempt regardless of their power rating. Also, cogeneration equipment with a combined heat and power system efficiency of at least 50 percent, or if the customer operates or buys from an on-site generation or cogeneration facility of 60 kW or less that is eligible for net metering, it will not be subject to an exit charge. Http://www.eea-inc.com/rrdb/DGRegProject/States/MA.html.

assessed fee multiplied by the customer's historical usage in kWh. Some are set up to be one-time payments while other states require payments over time. Fees are sometimes included as a competitive transition charge (CTC).

Natural Gas Rates

Nature of the Impediment

Natural gas-fired DG systems installed on a customer's premises are generally charged for gas use under residential or commercial retail rates. These rates are often based on usage patterns and volumes associated with space and water heating, or cooking. Distributed generation systems use considerably more fuel than a home or office furnace, and these higher volumes and load factors justify lower unit costs for natural gas than comparable non-DG customers. As such, DG systems are the only "power plants" required to pay retail rates for fuel; all other plants, regardless of ownership, are supplied via wholesale fuel contracts.

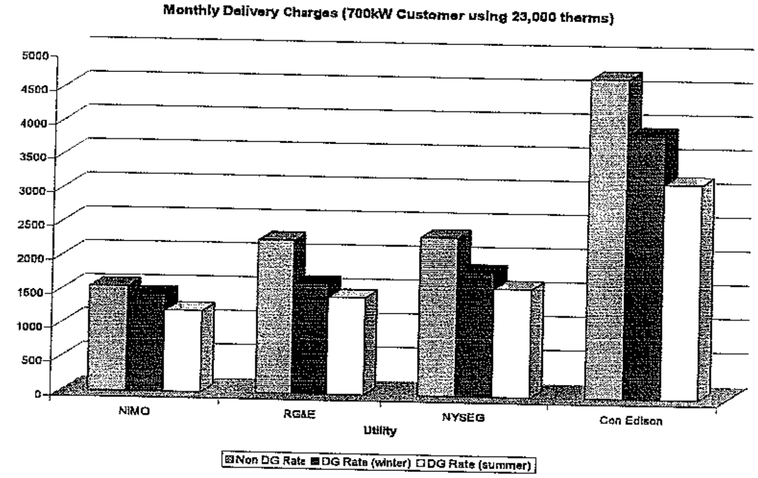
In many instances, the difference between wholesale and retail rates are sufficient to eliminate any financial savings the project may have generated, despite its significantly enhanced Btu utilization. The national fuel efficiency benefits of co-generation and combined heat and power systems are thus inadvertently masked by the financial impact of retail fuel costs.

Relationship to Regulation, Tariffs, and Markets

Because DG systems are located at or near the point of use, they typically receive low-pressure natural gas from the local distribution (LDC) service provider. The LDC thus argues that, absent retail markup, they cannot recover their own capital costs. Natural gas LDCs, and retail gas prices, are regulated by state public utility commissions.

In New York, the NYPSC issued orders in 2003 for LDCs to develop special gas-delivery rates for gas-fired generation at customer locations. As Figure 8.1 illustrates, the new DG tariffs submitted by New York regulated utilities and made permanent by NYPSC in June, 2004, effectively cut delivery charges in half, compared to non-DG retail gas customers, and provide 8-37% total savings over non-DG customers.

Figure 8-1. Monthly Delivery Charges for a 700-kW Customer Using 23,000 Therms



Source: Scott 2004.

In 2001, New Jersey Natural Gas Company (NJNG) petitioned the New Jersey Board of Public Utilities (NJBPU) to approve a DG tariff. In its rate filing, NJNG concluded the deployment of DG would improve its seasonal system load factor, make better use of existing assets, and offset potential price increases for existing customers. NJBPU found that the filing was reasonable and approved the rates in a January, 2003 decision.[76]

Compensation for Output

The primary benefit of DG to the customer is that it displaces power purchased from the utility when it is cost effective to do so. The current utility rate is the most natural basis for comparing cost effectiveness, but this is not always the appropriate metric. The buy-back rate or credit for displaced use varies from state to state and utility to utility, as does the mechanism for measuring and "counting" production. In general, the rates and mechanisms vary based on generator size and occasionally, power source (i.e., solar versus natural gas).

The operation of some DG devices is independent of customer power use. For example, a solar photovoltaic system on a vacation home may produce more power than is needed when the house is unoccupied. As a result, some states and utilities also restrict the total amount of power that can be "sold back" to the utility on the basis of customer use/bill. In other words, a customer may not be allowed to sell back to the utility more power than it uses on a monthly or annual basis. Any generation over that threshold is essentially "free" to the utility. Another way of restricting DG is to limit the total amount of DG installed or purchased to some fraction or amount of utility load. For example the utility may be required to purchase DG output up to the point that aggregate output exceeds 2% of total utility load.

Some DG generation facilities can provide surplus power and energy that can be sold into the market. For CHP facilities, the local thermal load can be satisfied and matching electrical output can provide

[76] State of New Jersey Board of Public Utilities. *In the Matter of New Jersey Natural Gas Company Distributed Generation Tariff Filing.* Docket no. GT01070450. New Jersey, January 8, 2003.

surplus electrical output for sales. For DG facilities in a retail setting, a project could easily have seasonal or daily surpluses that would be available for sales. For DG facilities that are focused on the wholesale market, the entire amount of output could be directed to the market. In all of these situations, the price paid for output will impact the viability of a project and lack of a fair price will be an impediment or barrier to economic DG or CHP facility development.

Various mechanisms can be used for paying for surplus DG output. For smaller generators, some states have embraced a concept called "net metering." In concept, net metering allows customer generation of certain sizes and types to get full retail rate credit for their output by "running the meter backwards." In practice, each state has its own rules for net metering. Some allow for full credit at the retail rate and others establish other, typically lower, credit values. Prices paid for surplus output can also be established through separate Power Purchase Agreements (PPAs) negotiated between the utility and the distributed generator under regulator-approved rules or through regional competitive mechanisms conducted by ISOs. Avoided-cost-based rates, developed in a number of states pursuant to PURPA have generally been replaced with these kinds of market-based mechanisms, anticipating or in response to the 2005 Energy Policy Act. Larger DG systems and systems on non-residential loads typically require additional metering at additional cost to the customer. This enables a greater variety of mechanisms for compensating DG owners for power they produce. It should also be noted that the 2005 Energy Policy Act includes a requirement that state regulatory authorities and nonregulated utilities consider net metering; however, it does not specify a metering mechanism or buy-back rate or credit. A summary of compensation mechanisms includes:

- Net metering where the meter "runs backwards" and the customer is compensated at its retail rate
- Net metering for compensation by the retail utility at prevailing wholesale rates (avoided costs)
- Sales into the wholesale power market in deregulated areas
- Compensation for capacity (reduction of demand charges)
- Compensation for reduction of transmission constraints under locational marginal cost pricing (LMP)
- Compensation for transmission and distribution system loss reduction.

It will become evident in the following discussion of each of these compensatory mechanisms that all are not offered by all utilities or available to all DG customers. Increased availability of each would significantly improve the economic environment for installation of DG systems. Further, utilities and regulators have historically allowed co-generation deferral rates to actively discourage DG. This disincentive rate is discussed at the end of this section.

Lack of Net Metering

Nature of the Impediment

Net metering is a policy option available to the states to promote environmentally preferred customer-located DG and its absence can be viewed as a barrier to deployment. There are several approaches to net metering. A simple method is to install the generation on the customer side of the meter and allow the meter to run backwards when the generator produces more energy than the generator and draw energy from the grid when load is larger than generation. In a given month, the customer can bank energy and is only billed for net consumption. A customer who generates does not receive any payment for generation, but receives a reduced bill and generation is valued at full retail rates. A second method of net metering, often called net billing, charges the customer retail rates for use and pays the customer a special rate for energy production. This type of net metering requires a meter enhancement to make it work. This approach provides payments to customers based on predetermined buy-back rates, typically the utility's avoided costs.

Utilities often argue that net metering is a form of cross-subsidy, since the retail rate credit invariably exceeds the utility's avoided costs. Technology proponents argue that net metering allows capture of benefits with a simple approach and that the cross-subsidy, if there is one at all, is exceeded by the overall benefits provided to the system by the on-site generation. Policymakers typically target the net metering program to small solar, wind, and other technologies that are deemed to be environmentally benign and, also, cap the amount of total net-metered generation allowed on a utility system.

Relationship to Regulation, Tariffs, and Markets

Net metering at the retail level is under the control of state regulators. It is often viewed as a policy implementation procedure that encourages addition of beneficial technology in the view of the state with a minimum of programmatic cost. State legislators often target technologies to certain renewable technologies such as solar and wind. For example, the Arkansas Renewable Energy Resources Act, which is emblematic of the laws in the many other net-metering states, states that "(a) Net energy metering encourages the use of renewable energy resources and renewable energy technologies by reducing utility interconnection and administrative costs for small consumers of electricity (*Arkansas Renewable Energy Development Act*, Act 1781 of 2001. HB 2325. Attachment 1, Section 2)." States also often cap the amount of net metered capacity to ensure than do not have a substantial or deleterious impact on utility operational and financial performance.

California has the nation's largest net metering program. The policy promotes renewable technologies to reduce environmental impacts, diversify fuel sources, stimulate economic development, and improve distribution system performance. Technologies include wind, solar, and biogas digesters. Net metering in California is currently capped at 0.5% of a utility peak demand.[77]

Utilities in the states listed in Table 8.6 offer net metering for certain classes of customers and technologies. (Interstate Renewable Energy Council 2006).

<u>Retail Buy-back Rates</u>

Nature of the Impediment

Distributed generation facilities that serve local load may see beneficial economics by selling surplus capacity and energy to the interconnecting utility or to the wholesale marketplace. Further, some DG facility installations have no or very small loads and are intended to sell output into available markets. If the means of selling output to the utility or into wholesale markets are not available, or if the prices offered for DG output are below market rates, DG facilities will be economically disadvantaged.

77 North Carolina State University, "Database of State Incentive for Renewable Energy (DSIRE)," Accessed September 15, 2006 at http://www.dsireusa.org/ last updated September 15, 2006.

Table 8.6. Net Metering Offered by States

State	Size and Technology	State	Size and Technology
Arizona	10 kW wind and PV	New Hampshire	25 kW PV, wind, hydro
Arkansas	25-100 kW renewables, fuel cells, and micro-turbines	New Jersey	2 MW renewables
California	1-10 MW PV, bio-gas, fuel cells	New York	10-400 kW PV, biomass, wind
Colorado	2-10 kW wind, PV, small hydro	North Dakota	100 kW renewables, CHP
Connecticut	100 kW renewables 50 kW fossil fuels	Ohio	25-100 kW renewables
Delaware	25 kW renewables	Oklahoma	100 kW renewables, CHP
Florida	10 kW PV, wind	Oregon	25 kW+ renewables, fuel cells
Georgia	10-100 kW PV, wind, fuel cells	Pennsylvania	Varies. renewables
Hawaii	50 kW PV, wind, biomass, hydro	Rhode Island	25 kW renewables, CHP
Idaho	25-100 kW renewables, fuel cells	Texas	20-50 kW renewables, fuel cells, micro-turbines
Illinois	40 kW PV, wind	Utah	25 kW renewables, fuel cells
Indiana	10 kW PV, wind, small hydro	Vermont	15-150 kW PV, wind, biomass, fuel cells
Iowa	500 kW renewables	Virginia	10-500 kW solar thermal, PV, wind, hydro
Kentucky	15 kW PV	Washington	25 kW renewables, fuel cells
Maine	100 kW renewables, fuel cells, CHP	Wisconsin	20 kW renewables, CHP
Maryland	200 kW wind, PV, biomass	Wyoming	25 kW renewables
Massachusetts	60 kW renewables, fuel cells, CHP		
Michigan	30 kW renewables		
Minnesota	40 kW renewables, CHP		
Montana	50 kW PV, wind, hydro		
Nevada	150 kW renewables		

CHP= combined heat and power
PV= photovoltaic

Relationship to Regulation, Tariffs, and Markets

FERC has a long history of involvement in framing markets for certain renewable and CHP technologies. PURPA mandated purchase of output from qualifying facilities (QFs) by utilities. The basis of the price of purchase was "avoided cost" in which the state determined the avoided cost of its regulated utilities.

EPACT 2005 requires FERC to modify its rules requiring purchase of output of QFs. The Act terminates PURPA's mandatory purchase and sale requirements if FERC determines that the facility has access to independent day-ahead and real-time markets and other non-discriminatory services.

One approach to this issue is net metering, described above. Some states have gone beyond net metering to require regulated utilities to directly purchase DG electric output.

California. A recent proceeding[78] in California addressed the issue of whether distribution costs should be "de-averaged" to reflect geographic differences, not in rates, but in credits or buy-back prices to be paid distributed resources. Such credits or prices would reflect the actual distribution savings that a distributed resource would provide. There was some support for this procedure because it would allow cost-based buy-back rates for DG that provided benefits by deferring new facilities in the areas that needed support. The California Public Utility Commission concluded that its rules permit utilities to enter into contracts with customers that install DG, thus allowing a utility to encourage DG site location.

Minnesota. *In the Matter of Establishing Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities Under Minnesota Laws 2001, Chapter 212,*[79] the Minnesota Public Utility Commission provided guidance to utilities for the design of buy-back rates for purchase of DG output. These provisions include a must-buy provision by utilities and also require that rates should reflect the value of the generation to the utility and the costs that the utility expects to avoid. Capacity payments would be appropriate if the utility shows a deficit in any year of a five-year planning period.

Wisconsin. For all generators below 20 kW, net metering provisions apply. Generators larger than 20 kW will receive buy-back rates are either negotiated or based on avoided costs as determined for that utility.

Wholesale Buy-back Rates

PURPA mandated utilities to purchase the output of certain small power production facilities, renewable energy systems, and CHP facilities, which qualified for designation as PURPA generators (QFs), at state-determined avoided costs. Section 210(m) of PURPA, which was added to PURPA by EPAct 2005, relieves utilities of the obligation to enter into new contracts or obligations with QFs if the QFs have nondiscriminatory access to wholesale markets described in Section 210(m)(1) of PURPA.

Policymakers and operators of regional grids are now beginning to address the issues surrounding the participation of customer-sited resources in wholesale markets. Grids and markets that were originally designed to optimize the operations of large, central generating stations are ill-equipped to capture the value of distributed resources and deal with their peculiar needs. Modifying the market rules, operational requirements, and, perhaps most important, the means of purchase and sale ("settlement" in the system operator's lexicon) is a resource-intensive and, in many instances, contentious undertaking. Still, progress has been and is being made.[80] The following are areas of wholesale market activity in which DG can play a meaningful role (EPRI 2003).

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78 California Public Utility Commission Proposed Decision of Commissioner Lynch January 10, 2003.8.3.2 Discussion: Contracting for Distributed Generation Obviates Need for Deaveraged Tariffs or Incentive Programs at This Time.

79 Minnesota Public Utility Commission, Docket No. E-999/CI-01-1023

80 Two examples of successful multi-stakeholder processes are the New England Demand Response Initiative (NEDRI, http://nedri.raabassociates.org/) and the Mid-Atlantic Distributed Resources Initiative (MADRI, http://www.energetics.com/MADRI/). NEDRI contributed to, among other things, the adoption of output-based emissions standards for distributed generation in Connecticut, Massachusetts, and Maine (and shortly in Rhode Island); the development of rules that allow demand resources, including end-use energy efficiency, to participate in the regional capacity market (see http://www.iso-ne.com/committees/comm_wkgrps/othr/drg/index.html); and the consideration by regulators of more dynamic retail pricing structures. The MADRI work is on-going.

Lack of Locational Marginal Price

Nature of the Impediment

Wholesale markets in the Midwest, the East, California and in Texas make use of LMP, to varying degrees, to manage congestion on the grid. LMP-based, day-ahead and real-time markets can encourage deployment of DG facilities in areas of the system where their output will be most highly valued. Whether the absence of LMP can be viewed as an impediment or barrier to DG development depends, in large measure, on overall prices in the market and on the market rules generally.

Locational marginal price calculations (from price bids) produce the top incremental cost to anyone that can deliver energy to specific locations on the grid. Having this locational component can be valuable to DG facilities if they are located in regions with high costs and where surplus output can be sold. Historically, these prices at peak and other times of congestion can be substantially higher than average. Where dispatch output can be controlled and matched to expected daily patterns, LMP pricing can support DG installations by offering them market prices for energy. The overall market benefits when local power is able to reduce system costs.

Relationship to Regulation, Tariffs, and Markets

Locational marginal pricing is an element of wholesale energy markets regulated by FERC. The calculation and operational parameters are provided by RTOs and ISOs operating in the United States. However, market operational rules, credit rules, and other factors are complex. Details are provided in regional market tariffs.

Lack of Regional Capacity Markets

Nature of the Impediment

On the grounds that the short-run energy markets are, by themselves, too volatile and risky to encourage and reward investment in new capacity, some ISOs have created (or are in the process of creating) capacity markets (installed capacity, or ICAP) aimed at providing suppliers a steady stream of revenues to cover some portion of their investment costs. In this way, longer-run system reliability can be assured. As alternative resources such as DG and end-use efficiency can satisfy reliability needs, the absence of a capacity market can be viewed as an impediment to their development.

For example, the New York ISO has a bidding system with prices for capacity at three geographic locations. Practically speaking, this means that the capacity price in New York City is usually higher than the rest of the state. The market administered by the NYISO makes it substantially easier for DG facilities to market and obtain a revenue stream from surplus capacity. The mere existence of a capacity market, however, does not necessarily mean that the problem is solved. The short-term (1-year) payment streams that the early ICAP markets provided have generally failed to provide the kinds of incentives that new investment requires. For this reason, both ISO-NE and PJM are currently in the process of redesigning their ICAP markets to compensate capacity providers not only for capacity today but also for the future (e.g., two, three, five years' hence) delivery of capacity.

Relationship to Regulation, Tariffs, and Markets

Regional wholesale capacity markets are under FERC jurisdiction and FERC has approved capacity markets in at least two regions. The PJM region and the ISO New England also administer capacity markets. Both PJM and NYISO have had success in programs for distributed generators that provide emergency system support, bid capacity or bid energy or demand response into the day-ahead market.

Credit for Loss Reduction

Nature of the Impediment

One of the benefits of DG, including DG facilities, is that transmission and distribution capacity and energy losses are eliminated or reduced by local generation, sited close to load. This means that the purchases of excess supply from the DG or CHP facility at or near a loads site is worth more than the same amount of capacity and energy from a remote site that is distance from loads.[81] For example, a utility purchase of capacity and energy could deliver to other nearby loads with losses that are negligible when compared to delivery from plants miles away. A lack of price recognition for these loss reductions can be an impediment to the expansion of DG facilities.

For wholesale situations, FERC has rate approval authority. Each transmission provider's Pro Forma Open Access Tariff[82] must specify the method for handling losses. Most tariffs allow a transmission user to provide its own capacity and energy losses for transactions and some allow the user to purchase these losses. For typical transmission service, wholesale users pay average losses with no reduction for local generation provided by DG facilities.

Relationship to Regulation, Tariffs, and Markets

At retail, state regulators determine utility buy-back rates for customer DG facilities. How these rules and retail buy-back rates can play in DG development has been discussed earlier. Buy-back rates are developed under regulatory rules and the treatment of losses is covered under this rule-making authority.

Most transmission tariffs generally call for the application of average system loss factors when calculating capacity and energy needs for delivery from network resources to network loads (without running local generation). This generally means that delivery of power and energy under Network Integrated Transmission Service (NITS) for a municipal utility with local generation would continue to pay for average losses even when generating and providing load with local supply generation. In many instances of NITS service, no credit is given for reduced losses provided by DG or CHP.

However, for certain ISO and RTOs, including MISO and the NYISO, FERC has approved another method of handling losses. This is an incremental-losses method that is based on calculating the cost for the ISO or RTO to provide the last MWh of loss supply. The loss calculation is used within the LMP process to give both this incremental value and the locational value of where the losses are supplied and used. In these instances, the ISO or RTO dispatches generation to provides the losses, load nodes pay

81 In fact, savings from reduced losses flow not only from the sale of excess DG power to the grid, but also (and primarily) from that portion of DG output that serves the customer on-site. The existence of the DG avoids the need for grid-supplied power to the customer and, therefore, also the losses associated with it.

82 Final Ruling on Order 888, RM947001, Open Access Tariffs for Interstate Transmission, December 31, 1996.

incremental costs for losses, and generator nodes are paid for these incremental losses. This approach is favorable to DG because it allows local generation to capture incremental value, which is generally higher than average value, and takes into account the location of the generation.

Co-Generation Deferral Rates

Nature of the Impediment

Prior to investing in an DG or CHP facility, commercial and industrial utility customers investigate the economics and feasibility of the new local generation by, among other things, comparing its total costs and benefits to continuation of service under the existing rates or contract. Customers for whom such analyses show on-site generation to be cost-effective pose a unique challenge to utilities. As utility profits are linked, under traditional price regulation, to sales (i.e., throughput) utilities naturally worry about the loss of energy and capacity sales to customers and often seek regulatory approval to offer special reduced rates (often called "co-generation deferral" or "competitive" rates) to retain the customer. Such rates reduce the value of the on-site facilities and often render it uneconomic. Utilities argue that loss of sales to key customers leaves a burden on the remaining customers and that it makes sense to retain a customer at a reduced rate (thus securing at least some revenue contribution to cover the utility's investment costs) rather than lose it altogether. DG developers and others argue that the utilities' offering of below-tariff rates to retain customers is an impediment to and barrier to adoption of valuable DG technologies and may constitute, in certain cases, illegal preferential treatment of particular customers.[83]

Relationship to Regulation, Tariffs, and Markets

Under state retail regulation, utilities typically request approval from state commissions to offer deferral rates to customers that would otherwise generate locally for some portion of supply. Approval is needed because offering a price break to an individual customer means that the customer would be paying rates that are less than those paid by other, like customers; the state regulatory commission determines whether the legal criteria that would justify a deviation from tariffs have been met. Any reduction in sales means that, all else being equal, the remaining customers in the rate class will be asked to pay a larger share of class-related costs to cover the portion no longer paid by the selected customer. It is up to regulators to determine whether there are any, or a sufficient level of, net system benefits to justify the discounted rates.

Table 8.7 provides a summary of some of the activities being used or discussed in states across the country to address the rate-related impediments to DG.

[83] State regulatory law prohibits the granting of preferential rates or other treatment to favored customers. Typically, rates are considered preferential (or, for that matter, discriminatory) when they lack a basis in cost for their difference from the rates charged to customers of similar size and usage patterns.

Table 8.7. Summary of Potential Solutions to Rate-related Impediments

Impediment	Solutions
Loss of Utility Revenue	• Performance Based Regulation (PBR) • Sharing of savings between utility and customer DG • De-averaging of buy back rates for DG
Standby Charges	• Waiving of standby charges in constrained areas or in cases where customer will guarantee load reduction
Exit Fees and Stranded Costs	• Requirement of proof that an asset is actually being stranded • Sunset provisions
Natural Gas Rates	• Rebates for customer-located DG, covered by federally mandated congestion charges (recovery of costs to administer rebate program) • Non-restriction of firm or interruptible service under which DG customer can receive service • Dual meters (gas and electrical output) • Riders from gas LDCs that guarantee DG customers are treated in the same manner as any other firm or interruptible customer • Legislation that insures a long duration of gas rebate • No performance standards with regard to gas
Lack of Net Metering	• Most states have a net metering program, but interconnection must be straightforward and not costly
Retail Buy-Back Rates	• States can direct resources to their most highly valued uses to more fairly compensate DG for the system benefits it can provide • Geographically de-averaged retail distribution credits • DG as less costly means of providing service where marginal costs of distribution are high
Lack of Locational Marginal Pricing	• Ability for DG to participate in wholesale market
Credit for Loss Reduction	• For retail situations, regulators could incorporate savings in line losses provided by DG into the regulated prices to be paid for surplus output • For wholesale situations and regional markets, expansion to incremental loss calculations would provide the correct price signal to distributed generators with surplus output to sell
Co-Generation Deferral Rates	• Deployment of DG should be considered in the context of least-cost provision of service, and the revenue question dealt with separately • Regulators allow pricing flexibility in low-cost areas of the distribution system only if the utility increases rates in high-cost areas

8.5 Other Impediments

Distributed generators may be subject to siting rules and regulations similar to those that apply to utility generation, depending on size. Regardless, any generator that is directly connected to the local utility grid will *also* be subject to rules adopted by that utility, usually with the concurrence of local regulators. These rules and regulations are primarily designed to ensure the integrity of the local utilities' service quality per state and federal regulations and to protect the safety of both utility staff and other individuals using the electric grid. The utility is also liable for certain impairments of service quality and for accidents and injuries associated with its power lines and other facilities. Accordingly, utilities and regulators have adopted a variety of rules, procedures, and fees to ensure anyone connecting electrical generating equipment to the utility's lines will not affect utility service quality or expose the utility to potential liability claims. Although these rules and procedures are essential, they are not uniform across utilities. As a result, some utility rules and procedures may present impediments to DG and some utility fees may be unjustified or extreme. The areas most often cited as potential impediments include the following:

- Unnecessarily expensive interconnection requirements
- Excessive or unnecessary application and study fees
- Liability, insurance, indemnification and dispute resolution requirements
- Untimely processing of interconnection requests.

<u>Interconnection Requirements</u>

Nature of the Impediment

When interconnecting a DG system to a utility distribution grid, the interconnection best meets both the utility's and energy customer's needs when it is done in a way that

- Ensures the safety and integrity of the grid
- Identifies and employs the most cost-effective design available.

The impediment and/or barrier that presents itself to DG installations is the potential for discriminatory requirements being placed on the interconnection by the local utility, that exceed the physical attributes of the DG system proposed. When these added requirements are placed on an installation (usually under the analytic umbrella of "safety"), the cost effectiveness of the installation can be greatly compromised and projects are often times abandoned.

Operation of a DG system that is interconnected to the distribution grid must not present any system protection concerns for other assets on the utility power system. Also, operation or failure of local generation must not threaten the safety of line workers or the safety of the public in general. For DG facilities, the issues of system protection and safety of workers and other people are typically addressed in a set of rules or requirements that are historically proposed by the local utility and approved by the state commission. These rules put in place a process that has several phases including application, review, studies, design hardware requirements, and testing.

Although these documents attempt to provide standard interconnect requirements, they all specify that the local utility has final approval on what needs to be done and, therefore, determines the cost of the interconnections. There is little to no recourse to settle any technical disputes in utility decisions and provisions regarding interconnection to their grid. This leaves the procedures vulnerable to discriminatory requirements that exceed the physical attributes of the system under consideration, and can negatively influence the decision to invest in a DG or CHP system.

Common industry practices related to interconnection rules and requirements that are identified as barriers to DG are the burdensome technical interconnection requirements (including expensive hardware) and the related costs of studies for interconnecting and other specific contractual requirements. These other contract requirements include mandated provisions for liability, insurance, indemnification, timeliness and dispute resolution, and are addressed in other sections. Since there has been no common standard and states vary considerably, DG manufacturers and vendors have had difficulty in addressing the different standards with common hardware and approaches.

Utilities maintain that the technical requirements are needed to ensure the safety of utility workers, ensure the quality of electric service, protect valuable system equipment and ensure that other customers are not subsidizing the DG facilities.

Distributed generation proponents state that, in some cases, these rules and requirements are excessive, arbitrary, time consuming, and add unnecessary costs to the projects. They also argue to regulators that overly burdensome provisions by utilities can be used to shelter the utility, show preference for the utility's own generation and fail to take advantage of DG benefits.

Relationship to Regulation, Tariffs, and Markets

The published rules and requirements for the interconnection of DG systems to the local distribution grids normally come under the oversight of the state commerce and/or utility commissions. To assist the states, several federal and national entities have developed "model interconnect standards." Some 13 states including California and Texas have worked extensively to standardize DG interconnection requirements and rules to minimize barriers to interconnection of new generation supply (U.S. Environmental Protection Agency Combined Heat and Power Partnership 2006). Overall, various parties have developed interconnection rules that tend to vary across the United States. While many rules are similar, there is no basic document that sets threshold levels, impact levels, study requirements or other matters.

Industry Response to Technical Interconnection Impediments

To assist in overcoming the barriers related to small generation technical interconnection procedures, The Institute of Electrical and Electronics Engineers (IEEE), through industry Standards Coordinating Committee 21, has developed and published two standards (1547 and 1547.1) related to interconnecting distributed resources with the electric power grid (IEEE Std. 1547-2003; IEEE Std. 1547.1-2005). These standards documents were developed through a broad stakeholder consensus process approved by the American National Standards Institute (ANSI) and now provide the basis upon which most (if not all utilities and states) develop their specific set of rules and requirements. At the present time, many of the design and study issues, that are the basis for the impediments and barriers, are only identified in the IEEE standards and their implementation is left up to individual states. The overall success of the IEEE standards in providing uniform approaches has yet to be fulfilled. While the IEEE work has provided a framework, rules and requirements are still being developed on a state-by-state basis.

Standard 1547.1 is a complementary standard that provides tests and procedures for verifying conformance to Standard 1547. The standard recognizes that the interconnecting equipment can be a single device providing all required functions or an assembly of components providing various functions. Standards 1547 and 1547.1 are the first two of a series of standards and guides under development to address interconnection of DG. Other standards are under development to address conformance test procedures, an application guide, and a guide for monitoring and control of resources. The intent of these standards and guides is to provide a single set of documents for technical requirements that can be used as a model on national, regional, and state levels. Thus, the authors' goal is that the standards and guides will be used by utilities and state and federal regulators in deliberations that formulate and streamline technical requirements for interconnection of generating technologies of up to approximately 10 MVA that would be installed on the utility distribution system.

The National Association of Regulatory Utility Commissioners (NARUC) developed a proposed interconnection rule and published a report entitled *Model Distributed Generation Interconnection Procedures and Agreement* in 2002 that addresses many issues related to the barriers that interconnection rules pose for the deployment of distributed resources (NARUC 2002). Whereas IEEE 1547 focuses on technical matters, the NARUC rule and others (such as the model developed by MADRI [Energetics, Inc., 2005]) also deal with a number of regulatory policy issues.

At least two other DG interconnection models have been developed. The Interstate Renewable Energy Council (IREC) combined many of the IEEE and FERC provisions in 2005 and produced a set of model provisions (IREC 2005). In addition, the National Rural Electric Cooperative Association (NRECA) group has developed a toolkit to help electric cooperatives with legal, economic and technical issues of customer-owned generation. The toolkit is available online to interested parties (National Rural Electric Cooperative Association 2006).

For the wholesale marketplace, FERC has ordered transmission providers to standardize interconnection procedure requirements for small generators 20 MW and under that interconnect to FERC-jurisdictional transmission facilities and plan to market output into wholesale markets that are regulated by FERC. Standardized process procedures and agreements are required. The policy drivers for these procedures are to limit opportunities for utilities to favor their own generation, to reduce unfair impediments to market entry for small generation, and to encourage investment in generation and transmission infrastructure.

FERC Order 2000 requires public utilities (investor-owned as defined by FERC) that operate interstate transmission to amend their open access tariffs to include standard interconnection procedures in a form similar to the Small Generator Interconnection Procedures (SGIP) adopted by FERC (70 FR 71760-71772). The SGIP standardizes many procedures and contract terms such as what constitutes a small generator, who pays for studies, testing and any network upgrades. The standard procedures provide three ways for a utility to evaluate a request for interconnection. First, a default study process is proposed that could be used for any small generator request. Second, a fast track and simpler process is proposed for generators no larger than 2 MW that have been certified (and tested) by a nationally recognized certification laboratory. Third, a process developed for certified inverter-based generators no larger than 10 kW can be used. All three processes are designed to ensure that the generation interconnection does not endanger the safety or system protection of the transmission system. They are also designed to remove any potential undue burdens placed on DG owners or installers by utility transmission owners.

While municipal and cooperative utilities are not under FERC regulation, FERC has obtained their involvement and cooperation in transmission rules and requirements—such as for interconnection—by using a "reciprocity" provision: municipal and cooperative utilities are not allowed to take advantage of open access transmission or regional markets unless they offer their own systems to others on comparable terms.

Application Fees and Study Costs

Nature of the Impediment

On the retail level, application fees and study costs by utilities can be a barrier to effective interconnection of DG facilities. High application fees that are not cost-based can deter development by adding an expensive front-end cost to development. In addition, expensive technical studies can be a front-end cost burden, depending on the situation. The situation where studies are required but technically not needed, adds an unneeded financial burden to DG or CHP developments.

Relationship to Regulation, Tariffs, and Markets

Several state regulators have moved to standardize many application fees and study charges. On the wholesale level, FERC has proposed a fast-track screening process for situations in which detailed interconnection studies are not needed.

State regulators have worked to develop procedures and processes that address the concerns of both project developers and utilities. Fees are often set as a function of facility size and screens are often used to determine those facilities that require added study, and a final fee can typically be imposed to cover any needed utility system modification. Usually, states develop an all-encompassing process that covers application, contract or agreement, commissioning, and testing. Table 8.8 details some typical values for the various fees.

Based on the theory that those who cause a cost should pay that cost, state rules generally make the generator pay for any upgrades or distribution system improvements required for proper interconnection of the generation.

Table 8.8. Distributed Generation Application or Study Costs by State

Jurisdiction	Application/Study Fees	More Detail
California	$0 Net metering $800 All Other under 10 kW +$600 Added Review $1400 Min. if customer elects bypass	Utilities to track but not charge customers for costs to study interconnection
Massachusetts	$3/kW with $300 minimum and $2,500 maximum	Interconnection study fees may apply at actual cost
New York	$350 Non-refundable $0 DG > 15 kW	Applied to cost of interconnection.
Texas	Expedited: <500 kW radial system <20 kW network system	Study fees could apply
Wisconsin	$0 <20 kW $250 >20 to 200 kW $500 >200 kW to 1 MW $1000 >1 MW-15 MW	No Engineering Review or distribution study fee Max $500 ea. Engineering Review & Distribution Fee Cost based Engineering Review & Distribution Fee Cost based Engineering Review & Distribution Fee

The NARUC model does not include suggested fees; they are under state jurisdiction. The FERC small generation agreement has a suggested fee of 50% of the good faith cost estimate for the feasibility study with a minimum of $1,000 (70 FR 71760-71772).

Liability, Insurance, Indemnification and Dispute Resolution

Nature of the Impediment

Certain contract provisions for interconnecting a generator, such as high liability and related insurance coverage, and onerous indemnification provisions, can be barriers to DG development. Such requirements are likely based on the installation of much larger generators; in such cases, the scale of the insurance required can substantially exceed typical coverage either for homeowners or for commercial establishments. Some utility-proposed insurance requirements may not be available to a certain class of customers, such as residential.

Efficient settlement of disputes between a DG developer and a utility is critical to the proliferation of clean DG. State and federal regulators have mandated certain dispute resolution processes to assist in facilitating beneficial DG. Texas, New York, and California have established processes with (1) initial informal/good faith processes, (2) specific time limits and (3) final resolution with the commission. For wholesale applications, FERC employs an alternative dispute resolution process.

Relationship to Regulation, Tariffs, and Markets

State commissions can and have determined insurance and other liability requirements for interconnected DG. Some typical liability insurance requirements are shown in Table 8.8. At the wholesale level, FERC frames the issues of liability, insurance, and indemnification, but leaves the quantities of liability up to contract negotiation.

The following is according to the FERC Ruling:

> "The Interconnection Customer shall, at its own expense, maintain in force general liability insurance without any exclusion for liabilities related to the interconnection undertaken pursuant to the Agreement. The amount of such insurance shall be sufficient to insure against all reasonably foreseen direct liabilities given the size and nature of generating equipment being interconnected, the interconnection itself, and the characteristics of the system to which the interconnection is made...(70 FR 71760-71772). "

Table 8.9. Liability Insurance Requirements for Certain Jurisdictions

Jurisdiction	Minimum Liability Insurance Coverage	More Detail
Minnesota	<40 kW $300,000 >40 kW to 250 kW $1,000,000 >250 kW $2,000,000	
New York	No coverage required of the customer.	
Vermont	<15 kW $100,000 >15 kW to <150 kW $300,000	Net metering program Net metering program
Washington	$200,000	
Wisconsin	<20 kW $300,000	The applicant shall name the utility as an

	>20 to <200 kW $1,000,000 >200 to <1 MW $2,000,000 >1 MW to <15 MW Negotiated	additional insured party. Each party shall indemnify, hold harmless and defend the other party.

FERC rules also limit liability of one party to the other for the amount of direct damage actually incurred. Neither party is liable to the other for indirect or consequential damages. The parties also agree to indemnify, defend and hold the other party harmless from any damages or claims made by third parties.

Industry Response to Contract and Related Barriers and Impediments

Beyond the technical interconnection issues, there have been several industry-wide efforts comparable to the IEEE interconnection work but covering contractual barriers and impediments other than technical interconnection topics. These typically contractual topics can be rates paid for surplus sales, rates and charges, liability, insurance, indemnification, or related provisions. Progress in addressing these issues has been made in state, regional, and federal venues. The primary focus of this report is an analysis of DG development barriers with respect to proposals, approaches, and positions taken in state, regional, and federal regulatory venues.

The NARUC model rule also addresses contract terms (NARUC 2002). This effort is parallel to the proceedings at IEEE and FERC and has been designed to harmonize state approaches to distributed generation interconnection. The model procedures and agreements are intended to be resource documents for state commissions and industry stakeholders and to serve as a catalyst for state proceedings on DG interconnection developments.

The documents have been developed through a working group of experts in the topic area. NARUC has drawn on the experience of those who have worked on these issues in various state proceedings. The resulting procedures and the agreement address various issues typically identified as barriers including timelines, fast-track processes, dispute resolution, construction responsibility, pre-certification testing, limitations of liability, indemnification, and insurance. The procedures and proposed agreement are designed for flexibility, allowing various parts to be modified by state regulatory decisions.

In a parallel effort with development of the SGIP, FERC promulgated a Small Generator Interconnection Agreement (SGIA) which contains FERC-approved contractual provisions to accommodate the interconnection of the generation (70 FR 71760-71772). The SGIA lays out the responsibilities and obligations of the parties for operation, metering, reactive power, testing, liability, insurance, dispute resolution, and other contract topics.

Several Regional Transmission Organization (RTO) or Independent System Operator (ISO) transmission organizations have made efforts to lower barriers for market entry of small generation facilities into wholesale markets. These particular RTOs and ISOs follow FERC rules for SGP and SGIA, but they have also worked to encourage market access for these generators. For example, the New York ISO and Pennsylvania/New Jersey/Maryland Interconnection (PJM) RTO both have implemented FERC compatible interconnection and agreement procedures. In addition, they allow small generation facilities to participate in various locational energy, capacity and demand response markets, thus, receiving market prices for delivered power and energy.

Timeliness

Nature of the Impediment

Utilities have historically managed themselves with much longer time frames than many unregulated businesses. Thus, there has been some natural tendency to allow prolonged periods to complete an interconnection technical evaluation by utility staff. A prolonged period for evaluation causes a burden for DG facility development when such studies and tests delay a timely decision by generation owners. The IEEE 1547 standard recognized this; part of the development effort for 1547 was to standardize tests and procedures, thereby enabling their quick completion.

In addition, the experience of many developers of DG sites is that the utility has multiple points of contact that make the developers unsure of who sets the rules. Some developers have experienced delays caused by the necessity to repeat the application process for multiple organizations within the utility.

Relationship to Regulation, Tariffs, and Markets

Several states have established rules to ensure timeliness of response to DG developers who request distribution service. Texas, California, and New York, among other states, have addressed this issue by establishing slightly different approaches. Texas Rule 25.11(1) requires that each transmission and distribution utility designate a person or persons who will serve as the single contact for all matters related to the interconnection request. Texas also specifies utility time periods for processing and studying user requests for service. New York has approached this differently and directs all applications for units under 300 kVA to be made to a state agency to ensure uniform treatment. The California Energy Commission (CEC) along with the Public Interest Energy Research (PIER) Group has developed a program to streamline the interconnection process (Overdomain, LLC, and Reflective Energies, 2005a). Under this coordinated approach, the average time from application to interconnection has dropped substantially. Table 8.6 describes the procedural steps and timelines for interconnection in New York, California, and Texas.

Under wholesale regulation at FERC, the proposed small generator procedures document puts into place fast-track procedures for interconnection requests with approval periods of less than 30 days should an installation meet these fast-track criteria (70 FR 71760-71772). The fast-track procedures are based on generator size, technology, and size in relation to feeder and substation load. Only certain sites and technologies need in-depth network studies and the customer owning the generation pays the utility for these studies.

Table 8.10. Potential Solutions to Other Impediments

Impediment	Solutions
Interconnection Requirements	• Stakeholders should work with states to continue developing interconnection standards that utilize IEEE 1547 as their technical basis, and the development of the set of IEEE standards should be completed. • Dispute resolution clauses within the state interconnect standards are needed such that technical differences that have major impact on implementation cost and safety can be resolved in an open and equitable manner.
Application Fees and Study Costs	• FERC-proposed procedures present a model that has been used by some states and might be paralleled by other states.

Impediment	Solutions
Liability, Insurance, Indemnification and Dispute Resolution	• Scaling insurance requirements based on the relative size of the generator, the nature of electrical interconnection, and physical potential for impact will provide the greatest balance between real financial liability and added project costs.
Timeliness	• Texas, New York, and California, among other states, have recognized the issue of timeliness and have instituted rules, requirements, and procedures to deal with the issues. These states have seen an improved process of DG through means such as a single point of contact, specified maximum study periods and a facilitation project involving stakeholders to improve responsiveness.

8.6 Major Findings and Conclusions

Many states are beginning to address the rate-related and other impediments to the installation of DG systems. A number of rules, regulations, and rate-making practices discourage DG because they impose costs or burdens that reduce financial attractiveness. In the vast majority of cases these rules and regulations are under the jurisdiction of the states, which means that they can vary by state and utility service territory, which in itself can be an impediment for DG developers who cannot use the same approach nationwide, thus raising DG project costs beyond what they might otherwise be. *Subtitle E – Amendments to PURPA of the Energy Policy Act of 2005* contains provisions for state public utility commissions to consider adopting time-based electricity rates, net metering, smart metering, uniform interconnection standards, and demand response programs, all of which help address some of the rate-related impediments to DG. The DG interconnection provision builds on the on-going work of the Institute of Electrical and Electronic Engineers (IEEE) to develop uniform DG interconnection standards. It is expected that the DG-related provisions of the *Energy Policy Act of 2005* will increase the level of activity in states across the country to address rate-related and other impediments to DG.

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Appendix A. DG Benefits Methodology – An Example

This appendix presents an example of a methodology that has been applied to estimate potential DG benefits to utilities, customers, and the general public. As discussed in this report, some of the benefits from DG are related to avoided or deferred capital investments; some are related to market pricing effects; and others are related to system efficiency enhancements. Given the scope of the potential, no single method can be used to estimate all of the benefits DG provides to a utility and/or the customers served by that utility. In this example methodology, therefore, separate approaches are used for each major component of DG benefits, including:

1. deferred generation capacity
2. deferred transmission and distribution (T&D) capacity
3. provision of reactive power
4. energy substitution, congestion relief, and losses.

This methodology is presented as an example of how the benefits of DG can be measured, but it should not be construed to disparage the use of other methodologies. A number of states and utilities have made significant efforts to assess DG and there are a variety of valid approaches that are designed to meet the specific needs of particular regions, service territories, or localities.

Regional variations in regulation, market rules, energy supply, and population density are responsible for much of the variation between the approaches most often used today. Yet there are other reasons why no standard methodology has emerged for estimating the benefits of DG, including the difficulty of obtaining accurate and applicable data. Given rising levels of competition in the electric power industry, information regarding location-specific infrastructure costs and location-specific loads and load projections is usually considered to be proprietary. This limits the ability of anyone without access to this type of specific data to make accurate assessments of DG benefits to the utility, customers, and the general public.

A.1 Example Approach to Estimating Deferred Generation Capacity

Utilities use the loss-of-load probability (LOLP) or loss-of-load expectation (LOLE) approach to determine the level of generation reserves that are required to maintain a given level of system reliability. This is often considered to be a rigid reliability requirement for capacity in an area.

Many restructured markets have organized capacity markets to ensure they have enough capacity available.[84] Thus, the marginal capacity price reflects the supply and demand equilibrium for power supplies; in other words, the capacity clearing price is the marginal offer at which existing power plant capacity is equal to the level of peak demand plus reserve requirements. If the market is working properly, and the price for capacity is adequate to encourage new investment, there should be sufficient capacity to meet the planning reserve margin over the system peak.

[84] Note that a capacity market is different than a market for energy, where suppliers actually produce something; in capacity markets, suppliers are being paid to have capacity available to offer into the energy market. The need for capacity markets stem partly from the existence of price caps in the energy market, which prevent plants running only a few hours out of the year from covering all their fixed costs through energy sales.

Figure A-1. Equilibrium in the Capacity Market

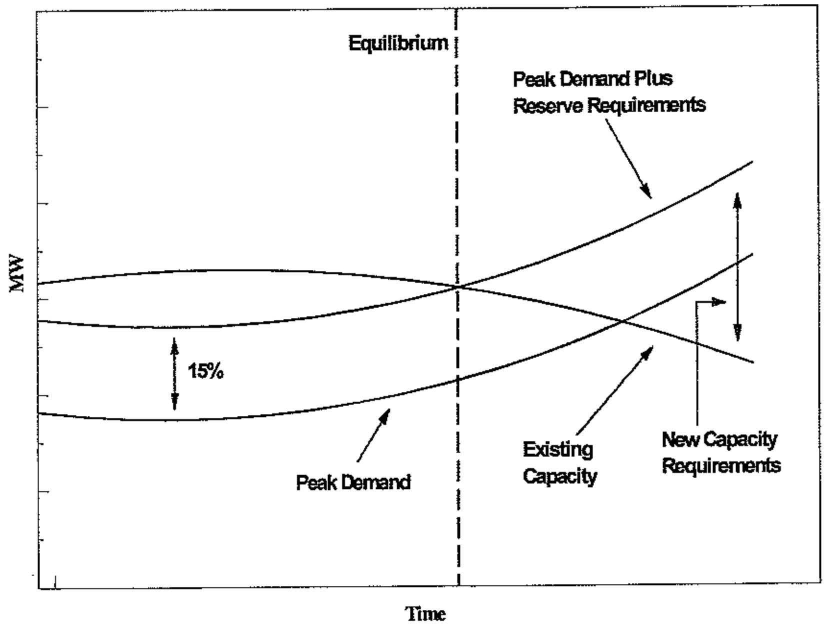
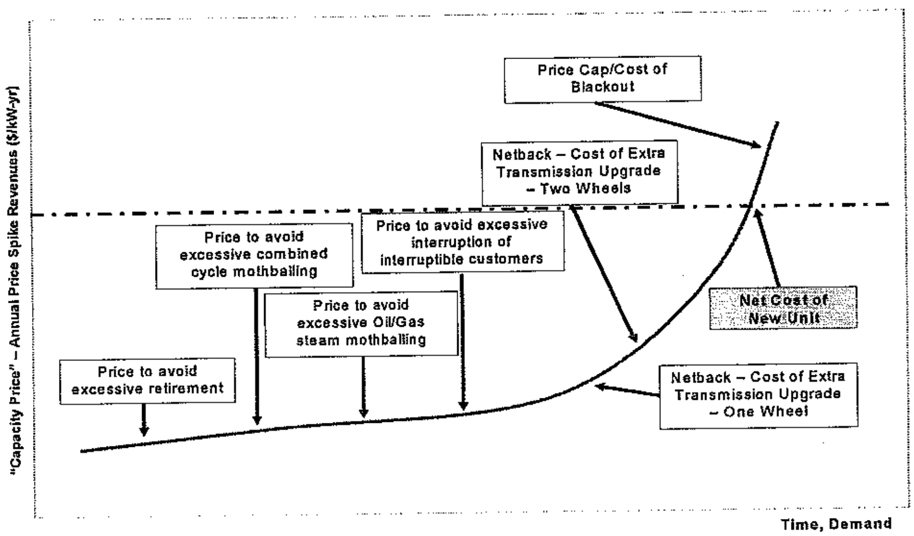


Figure A.1 shows the dynamic changes between capacity and supply that form the basis for the organized wholesale markets for electric capacity. This graph shows the peak demand growing over time and the existing capacity decreasing due to the retirement of aging power plants. The combination of growing peak demand and power plant retirements leads to the need for new capacity. These changes lead to adjustments in the observed equilibrium price where the equilibrium price is the net cost of capacity for the marginal generation unit (i.e., net of any revenue from energy sales). When there is sufficient capacity, the marginal unit already exists and the marginal cost of capacity is close to zero (as shown at the "equilibrium" time in Figure A.1); when there is not sufficient capacity, the marginal unit is a new unit with a potentially high cost of capacity.

The value of the deferred generation investment to the utility is the change in the marginal capacity price with and without the installed DG minus any capacity payments from the utility to the DG owner. For example, if the capacity price without a DG installation is $75/kW per year and the additional installation of DG capacity reduces capacity prices to $60/kW per year, then the value of the DG capacity is $15/kW per year. All units up to the last unit that provide capacity to meet demand and reserves in the market earn the capacity price. Thus, the total savings provided by the DG owner is the $15/kW per year capacity price reduction multiplied by the peak plus reserve demand. The utility should be willing to pay the DG owner up to $15/kW per year for the new DG capacity after accounting for any utility administrative costs in managing that DG facility. Any additional savings in generation investment deferral that accrue to the utility is expected to be passed through directly to consumers or through reduced rates.

The value of deferred generation capacity (capacity price net of energy margin) depends on the existing supply-demand balance. As shown in Figure A.2, the value of deferred generation capacity is lowest in a market where generation units economically retire due to excess capacity and highest in a capacity deficient market. Note that the netback price is the price less any payments to deliver the capacity such as the payment for transmission and losses.

Figure A-2. Competitive Market Capacity Price Setting Mechanisms – Illustrative



Least-cost production cost simulation models are used to determine the capacity price of a power system. Generally the capacity price of a system is mathematically expressed as:

Capacity Price ($/kW-year) = Capital Cost ($/KW) x Capital Charge Rate (%) + Fixed Cost ($/kW-yr) - Net Energy Margin[85].

where the Capital Charge Rate is a combined rate that covers debt payments, property taxes, insurance and return on equity.

The savings to consumers would be the capacity price differential multiplied by all the installed capacity up to the established reserve levels minus any payments made to the owners of the cogeneration and small power production facilities. This capacity-price-setting approach is an industry standard used in many industry-standard production cost models, such as the Integrated Planning Model (IPM®) used by ICF International (ICF) for the U.S. Environmental Protection Agency's power sector emission policy analyses.

A.2 Example Approach to Estimating the Value of Transmission and Distribution Deferral

It is more complicated to determine the deferred investment in T&D capacity than it is to determine that in generation capacity. The complexities come from the following issues.

One can examine the benefit of cogeneration and small power production on a single T&D feeder or for a geographically defined T&D network. The approach used to determine the benefit of deferred investment

85 This is the energy margin realized by the marginal unit in the market.

in a single T&D feeder is different from the approach used to determine the benefit for a defined T&D network.

While the capacity (in megawatts) of each and all generation facilities connected to an alternating current power system is usually known with reasonable certainty, the capacity of a single feeder or a bundle of transmission facilities in an interconnected alternating current power system is not known with certainty, as discussed in Section 2.

Transmission and distribution loading relief that can be provided by DG helps defer utility T&D investments either for reliability or for commercial energy transfers. Transmission and distribution loading relief may come from all three major services provided by DG resources, i.e., reduction in peak power requirements, provision of ancillary services including reactive power, and emergency supply of power.

Unlike deferred real power generation investments, estimating deferred T&D investment does not readily lend itself to linear programming production cost model-based analytic techniques. This example methodology includes estimating deferred T&D capacity for a defined T&D system.

Example Approach for a Defined Transmission and Distribution System

The approach described below may be used to determine the T&D investment deferral benefit of cogeneration and small power production facilities on the entire utility T&D system as a whole rather than a specific feeder. This approach was used by ICF Consulting to estimate the avoided cost of T&D capacity for the Avoided-Energy-Supply-Component (AESC) Study Group of the New England region (ICF Consulting 2005).

This approach comprises four major steps:

1. Develop data that provide the benefits in $/kW per year of deferred transmission capacity from the analysis.
2. Develop data that catalogue investments in transmission and distribution over a historical and/or forecast period of years.
3. Develop data that catalogue peak demand growth over the same historical period of years.
4. Develop data that calculate the annual carrying charge of those investments based on assumptions on taxes, financing costs, operational expenses, and other recurring costs.

Data on Deferred Investment

The deferred investment in $/kW per year (similar to the deferred generation investment) are here defined as the incremental investment that occurs over a period of time that can be attributed to load growth divided by the actual load growth in that period. This approach is a reasonable approximation for the incremental costs of investment associated with T&D.

The time period for which data are available and the quality of those data are very important to this calculation. A period of about 25 years is recommended (preferably 15 historical years and 10 forecast years) given the lumpiness in the T&D investment cycle. Depending on the accuracy of the data, appropriate weighting factors may be applied to the historical and the forecast data.

Data on Historical or Projected Transmission Investment

The time period requires a duration over which a reasonable amount of investment occurred or is projected to occur. The recommended period of time is 25 years in length, (i.e., 15 historical years and 10 forecast years). The data on investment costs specified each year in nominal dollars are summed to determine the incremental investment which has occurred over the base year to the final year in the series. The share (in a percentage) of the total investment which is believed to be related to load growth is specified. The default for this is set to 50% of the T&D investment. This share is particularly important because even without the benefit of installed cogeneration and small power production or other demand side management activity, some reliability upgrades may become necessary. The data are entered in nominal dollars but are converted to real dollars using the Handy-Whitman index for utility T&D costs trends for a long-term historical period. T&D investment costs have increased at a rate above general inflation which is reflected in the Handy-Whitman derived escalation factor. Note, the historical relationship of transmission costs to general inflation is assumed to continue at the historical rate going forward.

Data on Carrying Charge Rate

The annual carrying charge for T&D includes insurance, taxes, depreciation, interest, and operations and maintenance (O&M). These line items should reflect the costs associated with new investment which can be deferred or avoided. In several cases, such as insurance and property tax expense, the full value associated with that item would be avoidable and it is appropriate to apply the share of the costs associated with that line item calculated as a percent of the total existing costs as the avoidable amount. However, in the case of O&M cost, new investment projects benefit substantially through economies of scale gained from existing investment. Given these economies, the O&M for new investments would be a much smaller share of the total project costs than the existing O&M expenses are of the current existing plant.

The standard data for the carrying charge calculation largely rely on Federal Energy Regulatory Commission (FERC) Form 1. As with all other inputs in this analysis, the carrying charge is required to be in real dollars. Values entered in nominal dollars should be converted to real dollars using an inflation rate input. A schedule for distribution capacity having identical formulation and format may be used for distribution investments.

Data on Peak Load Growth

The peak demand growth over a specific historical and/or future time period consistent with the investment data is used to determine the incremental load growth for which T&D investments are planned. Special consideration to the following factors:

1. Since peak demand can vary widely from year to year, as seasonal temperatures affect consumption during peak periods, it is important to consider the effect weather may have had on historical information used in this analysis.
2. If peak is measured at the generation point, transmission and distribution losses will need to be added to the values to capture the $/kW per year incremental costs savings at the load level.
3. When using historical and forecast demand data, users should verify that the point of measurement (load versus generator) is consistent.

4. The peak load for the forecast period should reflect the driver of the forecast investment data. For example, if planning is done to an extreme peak load condition rather than a normal peak load condition, the forecast demand data should be entered for the extreme case that is consistent with the investment dollars.

A.3 Example Approach to Estimating Reactive Power Benefits

In both organized wholesale power markets, and traditional vertically integrated power markets, reactive power resources that receive payments are usually reimbursed their annual reactive power revenue requirement. For generators, this revenue requirement is derived using the AEP Methodology[86] which ensures recovery of only the investment costs associated with the installed reactive power producing facilities. There are two main groups of reactive power producing equipment that are compensated under the AEP Methodology, (1) the generator/exciter and, (2) the generator step-up transformers. The investment cost of the generator, exciter, and generator step-up (GSU) are determined from the net book value of these assets.

The portion of this investment used for reactive power production is determined by applying an allocation factor referred to as a "reactive allocator." The reactive allocator is determined from the technical relationship between real power measured in megawatts and reactive power measured in mega volt-amperes-reactive (MVAr). The sum of the square of these two components gives the square of the complex power capability, which is measured in mega volt-amperes (MVA). This is shown in the equation below:

$$MW^2 + MVAr^2 = MVA^2.$$

This equation may also be written as:

$$(MW^2/MVA^2) + (MVAr^2/MVA^2) = 100\%$$

In this form, this equation shows that the sum of the real power and reactive power components compose the total generating capacity. Thus, the reactive power component is ($MVAr^2/MVA^2$).

A portion of the investment in the real power production facilities is used to energize the "exciter." This component is determined by first determining the total investment in facilities used exclusively for the production of real power. The proportion of this real power investment that is used to energize the exciters is determined from the ratio of the real power consumption of the exciters to the maximum real power capability of the generators. This ratio is the real power contribution to reactive power production allocator. This ratio is applied to the real power plant base to obtain the proportion of real power investment used for the exciters.

Thus, the total investment in reactive power production facilities is the sum of the three components, i.e., the reactive portion of investment in the generator and exciters, the reactive portion of investment in the generator step-up (GSU), and the reactive portion of real power investment used to excite the exciter.

After determining all the investment costs in facilities associated with reactive power production, an annual carrying charge (also referred to as a fixed capital charge rate) is applied to the total cost of investments in reactive power facilities to determine the annual revenue requirement. The fixed capital charge rate is the percent of the overall investment in the reactive power production facilities required to cover fixed operations and maintenance costs, fixed general and administrative expenses, taxes and

[86] AEP Methodology is derived from American Electric Power Service Corp., Opinion No. 440, 88 FERC 61141 (1999).

insurance costs, principal and interest payments on capital and return on capital for equity investors for the investment in the reactive power production facilities over the life of the equipment.

See Figure A.3 for a Summary Schedule of Reactive Power Revenue Requirement of a typical generating unit. Note that for some markets a service factor may be applied to the revenue requirements to capture the percent of hours that the plant is in operation. After determining all the investment costs in facilities associated with reactive power production, an annual carrying charge (also referred to as a fixed capital charge rate) is applied to the total cost of investments in reactive power facilities to determine the annual revenue requirement. The fixed capital charge rate is the percent of the overall investment in the reactive power production facilities required to cover fixed operations and maintenance costs, fixed general and administrative expenses, taxes and insurance costs, principal and interest payments on capital and return on capital for equity investors for the investment in the reactive power production facilities over the life of the equipment.

See Figure A.4 for a Summary Schedule of Reactive Power Revenue Requirement of a typical generating unit. Note that for some markets a service factor may be applied to the revenue requirements to capture the percent of hours that the plant is in operation. (The numbers in the following figure are from an actual FERC filing that has been altered slightly to hide their source.)

Figure A.3 Illustrative Summary Reactive Power Schedule

Schedule 1

Reactive Power Revenue Requirement

Line	Description	Units	
	Unit Name		Centralia 1-2
1	Reactive Power Portion of Generator/Exciter Costs		
a	Cost of Generator	US$	40,000,000
b	Cost of Exciter	US$	2,000,000
c	Total Generator and Exciter Costs	US$	42,000,000
d	Reactive Allocator		12.00%
e	Cost of Reactive Power Producing Portion of Generator/Exciter	US$	5,040,000
2	Reactive Portion of GSU Costs		
a	GSU Cost	US$	7,000,000
b	Reactive Allocator		12.00%
c	Cost of Reactive Power Producing Portion of GSU	US$	840,000
3	Associated Plant Allocated to Reactive Power Production		
a	Total Plant Assets	US$	720,000,000
b	Ancillary Electrical Equipment	US$	20,000,000
c	Cost of Reactive Power Portion of GSU	US$	840,000
d	Cost of Reactive Power Portion of Generator and Exciter	US$	5,040,000
e	Other Production Facilities	US$	650,000,000
f	Plant Real Power Base	US$	44,120,000
g	Plant Real Power Contribution to Reactive Power Production Allocator		0.50%
h	Reactive Allocator		12.00%
i	Cost of Associated Plant allocated to Reactive Power Production	US$	26,472
4	Cost of Reactive Power Producing Facility		
a	Cost of Reactive Power Producing Portion of Turbo Generator	US$	5,040,000
b	Cost of Reactive Power Producing Portion of GSU	US$	840,000
c	Cost of Associated Plant allocated to Reactive Power Production	US$	26,472
d	Subtotal	US$	5,906,472
e	Total Fixed Charge Rate		19.31%
f	Annual Cost	US$	1,140,778
g	Monthly Cost	US$	95,065

Figure A.4 Illustrative Schedule for Determining the Annual Carrying Charge

	B	C	D	E	F	G	H	I
2		ANNUAL CARRYING CHARGE SCHEDULE						
3	Line	Description	Unit		Amount			Source Schedule 4
4	1	Operation and Maintenance Demand Expense						
5	a	Total Annual O&M Production Demand Expense	US$	40,000,000				
6	b	Total Associated Production Plant in Service	US$	800,000,000				
7	c	Average O&M Demand Expense						
8							0.0500	Line 1a/Line 1b
9	2	General and Administrative Demand Expense						
10	a	Total Annual G&A Production Demand Expense	US$	9,000,000				
11	b	Total Associated Production Plant in Service	US$	800,000,000				
12	c	Average G&A Production Demand Expense						
13							0.0113	Line 2a/Line 2b
14	3	Property Tax Expense						
15	a	Total Annual Property Tax Expense	US$	6,000,000				
16	b	Total Associated Production Plant in Service	US$	800,000,000				
17	c	Annual Average Property Tax Expense						
18							0.0076	Line 3a/Line 3b
19	4	Insurance Expense						
20	a	Total Annual Insurance Expense	US$	3,000,000				
21	b	Total Associated Production Plant in Service	US$	800,000,000				
22	c	Annual Average Insurance Expense						
23							0.0038	Line 4a/Line 4b
24	5	Depreciation Expense						
25	a	Book Depreciation Expense	US$	50,000,000				
26	b	Total Associated Production Plant in Service	US$	800,000,000				
27	c	SLDp		0.06250				
28	d	Depreciable Years "n"		16.0				Line 5a/Line 5b
29	e	SFDp = [(RoR/(1+RoR)^n-1]						Depreciable years "n" = 1/SLDp
30							0.0250	
31	6	Income Tax Expense						
32	a	Federal Income Tax Rate	%	35				
33	b	State Income Tax Rate	%	0				
34	c	Gross Income Tax "GIT"%		35				
35	d	Gross-up Tax Factor ("GTF")	%	65				Line 6a + Line 6b
36	e	Composite Income Tax Factor						100% - Line 6c
37							0.0160	(GIT/GTF)*(RoR+SFDp-SLDp)*(1-WdLTD/RoR)
38	7	Financing Expense						
39	a	Rate of Return (RoR)		Percent of Total	Cost Rate (%)	Weighted Average (Wd)		
40	b	Equity Common Stock	%	40	11.00	0.0440		
41	c	Preferred Stock	%	12	7.50	0.0090		
42	d	Long Term Debt (Ltd)	%	48	6.75	0.0324		
43	e	Total	%	100	25.25	0.0854	0.0854	
44	8	Total Fixed Charge Rate					0.1989	Line 1c+Line 2c+Line 3c+Line 4c+Line 5e+Line 6e+Lin

A.4 Example Approach for Estimating Energy, Transmission Congestion and Transmission Loss Benefits

When DG facilities such as combined heat and power (CHP)[87] provide energy, they substitute a portion of the system load and lower the marginal price of power for all consumers. Therefore, customers pay a lower electricity costs than would have been the case without the operation of the DG facilities. The reduction in power prices is directly passed-through from the load serving entities to their consumers. Similarly, by supplying load at the end-use location DG facilities help reduce transmission congestion and losses. The benefits from energy substitution, transmission congestion, and loss savings is analytically captured through production cost modeling of a reference case and a change case with and without the DG facility. The saving in production cost in the two cases captures the combined benefit of all three factors—energy savings, congestion, and losses—as illustrated in Figure A.5 below.

There are many commercially available production cost models that may be used to capture the combined savings from energy substitution, transmission congestion, and losses. Many of these models are based on linear programming optimization techniques. A schematic of one of these models in provided in Figure A.6.

87 CHP units tend to have higher generating efficiencies therefore they often substitute power from conventional sources.

Figure A.5 Combined Production Costs Savings from Energy Substitution and Congestion and Losses

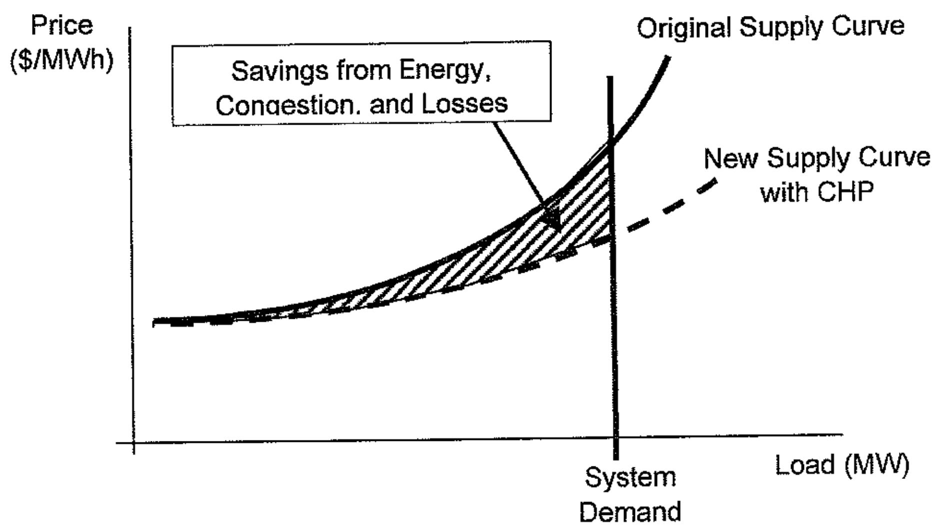
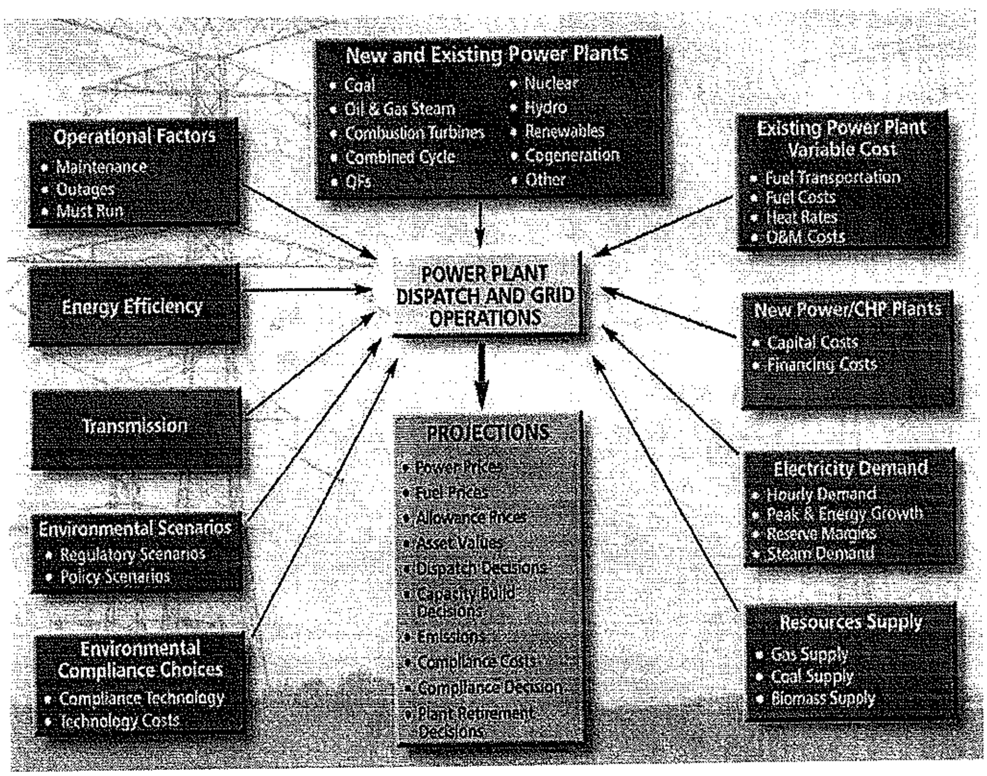


Figure A.6 Combined Production Costs Savings from Energy Substitution and Congestion and Losses



A.5 Summary and Conclusions

In summary, this Appendix provides example approaches to estimate the benefits of installed DG capacity to utilities and to customers served by utilities for each of the different benefit categories. Example approaches have been presented for estimating benefits from deferred generation capacity, deferred T&D capacity, reactive power ancillary services and energy, congestion, and losses. In conclusion, there are no uniform, or standardized methods or models for estimating the potential benefits of DG. There are several approaches in the literature that could be used. The methodologies presented in this Appendix are for illustrative purposes in an effort to outline the types of approaches that have been applied successfully, and to identify potential pitfalls to avoid.

Appendix B. Calculations to Establish Land Use for Typical Central Power Source and Distributed Generation Facilities

The variables and land-use values that are used to estimate the total amount of land required for central power sources are presented in Table B.1.

Table B.1. Typical Acreage for a Central Power Source

Fuel Type	National Percentag e (2004)	Adjusted National Percentage	Area Required For Utility Site Operation	Acreage Associated with Central Power Source
Coal	49.8%	51.82%	129 ha	165.19
Natural Gas	17.9%	19.92%	40.5 ha	19.94
Nuclear	19.9%	21.92%	1814 ha	982.54
Other Renewables - Wind	1.15%	3.17%	520 ha	40.72
Other Renewables - Hybrid Popular	1.15%	3.17%	121 ha	9.49
Total	89.9%	100%		1217.86 Acres
Difference in Total Percentage	10.1%			
Addition to Adjust Percentage	2.02%			

To derive the assumed acreage required for a central power source, the national percentage for electricity generation is combined with the land required for a utility site operation. However, the national percentage is first adjusted given that there is no land-use data on petroleum-based utility sites, and hydro sites are land-use intensive, the land-use estimates assumed for a typical central power source would be skewed. Secondly, the national percentage is adjusted based on the difference from the fuel types that are not included in the typical central power source land-use estimate. Lastly, the weighted average area required for a central power source is estimated by multiplying the area required for a utility site operation and the associated national percentage based on the fuel type of the central power source. Spitzley and Keoleian (2004) present their land-use data in hectares and these estimates are converted to acres given that most information in this appendix is presented on a per-acre basis.

The variables and land-use values that are utilized to estimate the amount of space used for a typical DE facility was derived from previous research presented by RDC. This publication provided information on the size of the typical DE facility and the footprint (sq ft/kW), which is provided in Table B.2.

Table B.2. Land-Use Estimates for Various Distributed Generation Facilities

Technology	Engine: Diesel	Engine: Natural Gas	Microturbine	Fuel Cell
Size	30kW - 10 + MW	50kW - 6 + MW	30 – 200 kW	100 – 300 kW
Footprint (sq ft/kw)	.22-.31	.28-.37	.15-.35	0.9
Average Footprint (sq ft/kW)	0.265	0.325	0.25	0.9

Technology	Engine: Diesel	Engine: Natural Gas	Microturbine	Fuel Cell
Average kW	5015	3025	115	1550
Total Footprint (sq ft)	1328.98	983.13	28.75	1395.00

The average footprint (sq ft/kW), average kW, and total footprint variables in the above table were calculated from the two rows, Size and Footprint. First the average footprint is estimated given the range of estimates provided by RDC (1999). Secondly the average kW is estimated from the size values. These two estimates can be used to calculate the total square footage that could be expected from these forms of DG facilities.

To assess the total land area that could be saved from expanding DG resources, the difference between the area typically used for a central power source and the DG facilities used for case studies is estimated. This estimate is the maximum available land resources that could be saved due to establishing the specific case studies reviewed in this analysis. The estimates for each case study are presented in Table B.3.

Table B.3. Open-Space Estimates for Case Studies

Case Study	Surface Area-Square Footage	Surface Area-Acreage	Open-Space Estimates (acres)
The Philadelphian Condominium	503	0.01	1217.85
Columbia Boulevard Wastewater Treatment Plant	200	0.004	1217.83
Santa Rosa Island Housing Facility	2,304	0.05	1217.85

To estimate the column in Table 7A.3, the difference between the typical acreage required for a central power source (1217.86 acres) and the land use used by each case study is utilized. The assumed surface area required for each case study varies based on information presented by the DOE in regards to the case study and information published by the RDC and presented in Table 7A.2. For example, the land-use information for the Philadelphian Condominium case study was derived from information on the total land utilized by the facility and the CHP unit. The land-use information for the Columbia Boulevard Wastewater Treatment Plant was extracted from RDC (1999). On the other hand, the Santa Rosa Island land-use amounts are based on data presented by Spitzley and Keoleian (2004), land-use values for various solar facilities, which is equal to 365.97 sq ft, which is equivalent to 0.01 acres.

Appendix C. Further Justification for Land-Use Benefits Values

The land-use values used for the quantitative analysis for this appendix were not established through a rigorous statistical assessment but instead through a basic review of land-value estimates from previous research publications. A literary justification for the land-use values is presented in this appendix. Information on the value of agriculture-based open space is presented below. Following this appendix, the ROW acquisition cost estimates are further discussed.

The open-space dollar-value estimates observed in this appendix are assumed to range between $171.72 and $4,687.00 per acre. The information used to choose this range of values is presented in Table C.1.

Table C.1. Price-Per-Acre Open-Space Estimates from Previous Research

Author	Low Range (Price Per Acre)	High Range (Price Per Acre)
Irwin	$4,687.00	$23,437.00
Lynch and Lovell	$1,165.00	$4,685.00
Conservation Reserve Program (CRP)	$121.00	$145.40
USDA (Commercial Land Value)	$290.00	$11,200.00

Irwin (2002) and Lynch and Lovell (2002) reviewed the value of preserved lands near the Washington D.C. – Baltimore metropolitan area. These estimates would be considered the upper limit of price per acre given the proximity to urban area and the influence of the Chesapeake Watershed conservation efforts. Irwin's high-range estimate is excessive in comparison to the rest of the literature reviewed. However, the low-range estimate from Irwin is within the range presented by Lynch and Lovell. The upper range presented by Irwin was chosen for the upper-range estimate in this analysis. In addition, the high range presented by Irwin is excessive in comparison to the reviewed literature. In terms of the lower value, the Conservation Reserve Program (CRP) estimates were used given the previous research from the United States Department of Agriculture (USDA), Economic Research Service (ERS) and the similar values between the CRP and the lower value of USDA commercial agriculture land estimates (Feather et al. 1999).

On the other hand, the ROW acquisition cost dollar-value estimates presented in this section range between $1,780 and $60,000. The information used to choose these range of values is presented in Table C.2.

Table C.2. Price-Per-Acre ROW Acquisition Cost Estimates

Author	Low Range (Price Per Acre)	High Range (Price Per Acre)
DOE EIA (2002 and 2003)	$1,314.96	$1,780.55
AEP (average)	$39,075.00	

Author	Low Range (Price Per Acre)	High Range (Price Per Acre)
Parker (natural gas pipeline)	$13,000	$60,000.00
Indiana Highway[88]	$45,000.00	$70,000.00
Arizona Highway[89]	$45,000.00	$187,000.00

The land purchase for ROWs used for electricity transmission lines in 2003 was equivalent to $1,314.96 per acre. This estimate did not include legal fees or the required services to alter assets located on the land resources used for ROWs. There is no additional research that has validated this level except for the data in 2002. Additionally, the low-range value presented by the Energy Information Administration seemed excessively low in comparison to the literature on electric transmission ROW acquisition costs. In turn, the 2002 estimate that is greater than the 2003 estimate was chosen as the lower limit estimate for this analysis.

The upper-limit value of $60,000 falls between the estimates observed in the two highway publications reviewed in this research effort. The vehicular transportation industry typically incurs the greatest level ROW acquisition costs. In addition, this upper-limit value is observed in Parker (2004) for 20-inch natural gas pipelines. Therefore, this value is chosen as an upper-range estimate for per-acre electric transmission ROW acquisition costs. The average estimates between the range of values concluded for this research effort, $1,780 and $60,000, present a median estimate of roughly $30,000, which is similar to the average per-acre ROW costs observed by a proposed transmission line presented by the AEP, $39,075 (AEP 2006).

88 This information was derived from Indiana Department of Transportation and the Federal Highway Administration, 2003. "US 31 Improvement Project, Interstate 465 to State Road 38; Draft Environmental Impact Statement" (DEIS)" Data developed by Parsons Transportation Group, Inc. June.

89 This information was derived from Arizona Department of Transportation, 2006. "Williams Gateway Corridor Definitions Study Final Report," Phoenix, Arizona. Accessed September 22, 2006 at http://tpd.azdot.gov/planning/Files/cds/williams/FR1_Williams%20Gateway%20Final%20Report.pdf

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000445

PREPA'S Hearing for EPACT 2005 Sec. 1252 and 1254 comments by Gerardo Cosme-Núñez, P.E., July 10, 2007.

My name is Gerardo Cosme-Núñez. I am a Licensed Professional Engineer, and active member of the Professional College of Engineers and Surveyors, The Puerto Rico Chamber of Commerce on which I am a member and former President of their Energy Committee, and a member of the Institute of Electrical and Electronics Engineers. I am coming as a citizen, a Professional Engineer and as the owner of a business that for nearly the past 15 years has been working in the energy field. Hence, as an electrical energy consumer, an engineer, an entrepreneur, and a conscientious citizen who desires the best for Puerto Rico's economic prosperity and global environmental benefits, I request that PREPA adopt EPACT 2005 sec. 1251 called Net Metering and Additional Standards, sec. 1252 called Smart Metering and sec. 1254 called Interconnection.

Today's (July 10, 2007) PREPA hearings are dedicated to sections 1252 and 1254 only. I assume that this is it because there are less than 30 days for PREPA respond to FERC. Therefore, my comments at this time will be in reference to sections 1252 and 1254 only. However, I request that PREPA work on and prepare hearings concerning section 1251, Net Metering, with much more advance notice than this one. These EPACT 2005 sections are indeed complex technical issues, and third party participation of highly qualified individuals and organizations are crucial to implementing successful programs such as Net Metering, Smart Metering, and Interconnection standards for the utility and customers benefit as well as for the general well being of Puerto Rico.

One final point in my introduction here is that this hearing is a reflection of how Puerto Rico lags behind the rest of the world with respect to energy efficiency and renewable energy incentives. First, this hearing is set less than 30 days from the date for PREPA to respond to FERC on the issues of this hearing. Second, the document prepared by PREPA presenting their position to its customers is poorly written with typographical errors. This creates the impression that PREPA's vast resources are not employed to their expected potential, making me and you think that their technical and economic assessments presented in the document in question may be equally flawed. Third, this hearing is not supposed to be set by PREPA. This hearing should be set by the energy regulatory agency of our territory (which does not exist, but is supposed to oversee our utility) as stated in EPACT 2005. PREPA by default is our utility and our government energy regulatory agency at the same time. PREPA stated that they hired EPRI to conduct a study on EPACT 2005 issues. As a taxpayer, I request that the government agency handling EPACT 2005 issues, which is PREPA, make that study publicly available.

Local Background

The Public Utility Regulatory Policies Act of 1978 (PURPA) requested that utilities purchase energy from co-generators and renewable energy resources and from small power producers at least at what is called the avoided cost.

In 1983, PREPA, in response to PURPA, published the document entitled: "Rates and conditions of service for co-generators and small electric power producers," in which they establish the process of how to comply with PURPA requirements. This Regulatory document was then

derogated at the end of the nineties. From that date to the present, PREPA is still required to comply with PURPA requirements. Therefore, PREPA must evaluate each case individually, due to their lack of a structured process to do so. Today in Puerto Rico, if any residential, commercial or industrial customer wants to connect their distributed energy equipment to the grid under PURPA Rules, the customer does not know what PREPA office to visit, what process to follow, or what application to fill out; and most PREPA staff will not know any of this information if questioned about it.

So, what do we have for Standards today, 29 years after PURPA? An old PREPA document that can be used as guideline, but there are no formal guidelines or standard up to date. On the other hand we have the IEEE 1547, "Standard for Interconnecting Distributed Resources with Electric Power Systems" pending to be adopted on August 8, 2007 and the UL 1741, "Standard for Inverters, Converters and Controllers for use in Independent Power Systems." This standard is based on IEEE 1547 and is intended for equipment manufacturers to ensure appropriate product safety requirements.

Comments in Section 1254: Interconnection

The purpose of EPACT 2005 proposing the adoption of IEEE Standard 1547 is to make interconnection technical issues uniform between states and between utilities. Although this is not the case for Puerto Rico, which has an isolated electrical system made of only one utility, PREPA, they should accept this standard as proposed in EPACT 2005. This standard establishes criteria and requirements for interconnection of distributed resources with electric power systems. It provides requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. PREPA may use other guidelines such as the one published by the *National Association of Regulatory Utility Commissioners* (NARUC), as stated in the PREPA document, for the administrative protocol process of the interconnection with their customers.

Comments in Section 1252: Smart Metering

Sec. 1252 includes more than the segment (14), which is referred by PREPA as *Time-Based Metering and Communications.* Therefore I will relate to the entire Sec. 1252.
The PREPA hearing document establishes that they have TOU rates for their industrial and commercial customers. However, if you read the PREPA document entitled "TARIFAS PARA EL SERVICIO DE ELECTRICIDAD" you may question whether TOU rates are really offered to industrial and commercial customers. In that document, PREPA defines TOU-P, TOU-T, and SR-TOU-T for industrial and commercial customers with a minimum demand of 1 MVA. These customers can do the following:

- Peak to off peak periods of load transfer,
- Add loads at off peak hours, or
- Reduce loads at peak hours.

Few small industrial and commercial sites have a demand of at least 1 MVA, which limits the availability of this kind of rate service; however, the following, taken from that same document

is even more disconcerting: "Time of use rate for air conditioning systems with cold storage denominated TOU-C. This rate applies only to air conditioning systems with cold storage of commercial or industrial customers. This air conditioning system should have a minimum cooling capacity of 25 tons, and from the cold storage means, al least 25 percent of its cooling capacity has to be displaced to off peak hours." In addition, the client should present a study that demonstrates the load amount that will be transferred to off peak hours, and operation strategies, among other unspecified requirements. As a final punch they add: "The load consumption and load demand of the air conditioner with cold storage will be measured separately from other client loads."

An analogy for a residential TOU arrangement might be the following: This service applies exclusively for the residential customer's TV set. This TV set should have a 54 inch screen or larger and must used at off peak hours to watch David Letterman on CBS instead of Larry King Live on the next channel.

In conclusion, actually no time-based rates are offered by PREPA for the vast majority of the industrial and commercial sector contrary to the essence of the EPACT 2005 purpose, as quoted below from the beginning of EPACT 2005, section 1252:

" (14) TIME-BASED METERING AND COMMUNICATIONS. -(A) Not later than 18 months after the date of enactment of this paragraph, each electric utility shall offer <u>each of its customer classes, and provide individual customers upon customer request</u>, a time-based rate schedule under which the rate charged by the electric utility varies during different time periods and reflects the variance, if any, in the utility's costs of generating and purchasing electricity at the wholesale level. The time-based rate schedule shall enable the electric consumer to manage energy use and cost through advanced metering and communications technology."

Finally, the PREPA document does not provide enough information to justify their reluctance to adopt EPACT 2005 sec. 1252, and their assessment is based on guesses. For example they claim to expect low interest by residential customers, as occurred in some place on the US mainland. However, there was not even a poll to justify this assumption.

Therefore I request that PREPA provide Smart Metering for all their clients as proposed in EPACT 2005. This standard should be well designed and implemented to ensure PREPA profitability as well customer satisfaction. This kind of program could be very important for our impaired economy to provide incentives to our industrial and commercial sectors to provide more job opportunities. Besides, all residential customers should enjoy the benefit of time-based rates as cell phone users enjoy the same at nights and weekends. Anyhow I might switch from Direct TV to PREPA TV cable if they offer me a reduced package, which includes electricity. Not to mention that if PREPA is ready for cable and Internet through their electrical network, sure they can figure out how to read my meter in a more effective manner.

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10 de julio de 2007

EPACT 05- Oficina del Consultor Jurídico
Autoridad de Energía Eléctrica
PO Box 364267
San Juan, PR 00936-4267

REF: VISTA PÚBLICAS
Adopción de Secciones 1252 y 1254 del Energy Policy Act del 2005

Buenos Dias

Mi nombre es Fernando Abruña. Soy Arquitecto practicante, Director del Taller de Diseño Sustentable de la Escuela de Arquitectura de la UPR, Presidente del US Green Building Council- Capítulo del Caribe, miembro del American Institute of Architects- Capítulo de Puerto Rico y del Colegio de Arquitectos y Arquitectos Paisajistas de Puerto Rico, ORGANIZACIONES PROFESIONALES los cuales represento en esta vista y quienes me han autorizado para así hacerlo.

Hacemos constar, por este medio, nuestro endoso y recomendación para que se adopten los estándares: "Time- Based Metering and Communications" (Sec. 1252) y el "Interconnection Standards for Distributed Resources" (Sec. 1254) que forman parte del Energy Policy Act del año 2005 la cual enmendó la Public Utility Regulatory Policy Act (PURPA) de 1978. Recoemendamos también el que se aproveche la oportunidad y se apruebe la Sección 1251, Net Metering ya que las tres están intimamente relacionadas.

Como marco de referencia, PURPA es la Ley federal establecida en el año 1978 que establece que la Autoridad de Energía Eléctrica (AEE) tiene la obligación de comprar la energía de cogeneradores o pequeños productores de electricidad utilizando fuentes renovables al costo evitado.

En 1983, la AEE publicó su Reglamento titulado; "Rates and conditions of service for cogenerators and small electric power producers" el cual fué derogado a finales de la década de los noventa. Desde esa fecha hasta el presente la AEE continúa con la obligación de cumplir con la Ley de PURPA, por lo que evalúa cada caso de forma individual por no tener un Reglamento definido.

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Preámbulo a la Sección 1252:
El estándar 1252, conocido también como "Smart Metering" obliga a la AEE a considerar tarifas de uso por horario a sus clientes en todas sus clases. La fecha límite para determinar la implantación del "Smart Metering" es el 8 de agosto de 2007, menos de un mes a partir del dia de hoy.

Recomendamos el estándar "Time- Based Metering and Communications" (Sec. 1252) por las siguientes razones:
Este estándar permitirá que diferentes usuarios, comerciales y residenciales entre otros, puedan obtener una tarifa más baja de consumo en horas nocturnas o fuera de pico. Este tipo de estructura tarifaria abona a mejorar la viabilidad económica de fuentes renovables de energía como lo son los sistemas fotovoltaicos y sistemas eólicos que ya cuentan con varias intalaciones en la isla. La Escuela Ecológica de Culebra diseñada por nuestras oficinas para la Autoridad de Edificos Públicos y el Departamento de Educación de Puerto Rico es uno de ellos.

La estructura tarifaria que posibilita este estándar permitirá que los sistemas fotovoltaicos puedan generar electricidad durante el día, cuando el consumo en la isla (y en la Escuela) es mayor, y alimentarse de la red de la Autoridad durante la noche cuando el Sol no está en nuestros cielos.

Este estándar permite la instalación de sistemas de fuentes renovables de energía eliminando la necesidad de un banco de baterías equivalente a aproximadamente 25% del costo total de sistemas autónomos haciéndolos, por lo tanto, más económicos. La eliminación de este costo acorta proporcionalmente el periodo de recobro de la inversión inicial haciendo más atractiva la opción de fuentes renovables de energía para la población en general. La eliminación del banco de baterias reduce además los gastos de mantenimiento y elimina el talón de aquiles de estos sistemas ya que las baterias tienen una vida útil limitada si la comparamos con la larga duración de los paneles y abona además a la sustentabilidad ecológica de sistemas fotovoltaicos y eólicos ya que la disposición de las baterias supone un proceso de mitigación ambiental.

Este estándar, conocido comunmente en Inglés como "Smart Metering" preparará el terreno para que la Autoridad pueda facilitar la adopción del sistema de Medición Neta ("Net Metering")Sección 1251, ahora.

Aprovecho esta ocasión para declarar y solicitar públicamente a esta Autoridad, que al aprobar la adopción de las secciones 1252 y 1254, adopte la sección 1251 y que permita y

adopte el sistema de Medición Neta en la Escuela Ecológica de Culebra del Departamento de Educación para el inicio del año escolar en Agosto de 2007. La Autoridad está capacitada para hacer dicha conexión y el National Electrical Code bajo el cual se diseño el sistema, aborda y atiende las preocupaciones de seguridad en el sistema de interconexión que pueda tener la Autoridad.

El Departamento de Educación es uno de los mayores deudores de energía de la Autoridad. Fomentar escuelas como la de Culebra que generen parte de su electricidad mediante el uso de energía solar no solo es una política sabia para la Autoridad si no además para todo el sector consumidor en la isla. Iniciar el sistema que propone la adopción del estándar 1252 facilitará el mantenimiento del sistema en la Escuela.

Más de 42 estados de la nación norteamericana han adoptado el sistema de Medición Neta, incluyendo a las Islas Virgenes, que sufre condiciones de isla, costos elevados de generación y dependencia en la quema de peróleo como ocurre en Puerto Rico.

PROFESIONALES Y

Más de treinta (30) organizaciones privadas, sin fines de lucro y personas de prestigio, en el campo de la energía y la sustentabilidad, nos han dado su endoso para que la Autoridad de Energía Eléctrica inicie un sistema de Medición Neta en la Escuela de Culebra. A continuación menciono algunos de ellos:

1. Colegio Ingenieros y Agrimensores de Puerto Rico
2. Colegio Arquitectos y Arquitectos Paisajistas de Puerto Rico
3. American Institute of Architects, Capítulo de Puerto Rico
4. US Green Building Council, Capítulo del Caribe
5. Casa Pueblo, Adjuntas
6. Georgie Bernardette, Al Gore Climate Project
7. Sociedad de Historia Natural de Puerto Rico
8. Alianza Ciudadana Para la Educación en Energía Renovable (ACEER)
9. Emerging Green Builders, Capítulo del Caribe
10. Sierra Club de Puerto Rico
11. Misión Industrial de Puerto Rico
12. Escuela de Arquitectura, Universidad de Puerto Rico
13. Fondo de Mejoramiento de Puerto Rico
14. Dr. José Molinelli, Ciencias Ambientales UPR
15. Dr. David Serrano, Director Carro Solar, RUM
16. Arq. Jorge Ramirez, CoDirector, Décalo Solar 2007

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17. Ing. Angel R. Zayas, Presidente, Comité de Diseño, Sociedad de Ingenieros Electricistas
18. Alexis Molinares, Ecólogo
19. María Juncos Gautier, Centro de Estudios Sustentables, UMET
20. Dr. Gerson Beauchamp, Ing Eléctrica RUM, Décalo Solar 2005
21. Ing.Gerardo Cosme, Solartek
22. Ing. Eduardo Tobaja, Advance Technology Products
23. Dr. Colón Negrón, Energtech
24. Dr. Eduardo García, TecnoSun
25. Vadim Nikitine, Commercial Centers Management Inc
26. Lino Aponte, Casa Solar
27. Ing. Felipe Bermudez, IB Homes Inc.
28. Arq. Vincent Pieri, LEED AP
29. Diego Sorroche-Fraticelli, Puerto Rico Appraisers
30. Arq. Luis Huertas, LEED AP
31. Carmen Pura Rodriguez, Educadora Ambiental, Univ. Sagrado Corazón
32. Yahaira Graxirena, Habitat Urbano: Planificadores y Arquitectos
33. Múltiples Ingenieros y Arquitectos de PR

Aunque entendemos que la Autoridad tiene hasta agosto de 2008 para demostrar porque puede o no adoptar un sistema de medición neta, exhortamos a la Autoridad a que inicie este programa ahora en la Escuela aunque sea solo inicialmente en los edificios del Gobierno como un gesto de su deseo y disponibilidad de promover fuentes alternas de energía en Puerto Rico. El ahorro de una agencia se compensa con el alegado costo adicional sobre el costo evitado que la Autoridad ha argumentado en el pasado. Lo justo y esperado por la comunidad consumidora es que la Autoridad venda y compre energía eléctrica de usuarios, como lo es esta escuela, al mismo precio.

La Autoridad de Energía Eléctrica podría dar un buen ejemplo de su compromiso con el futuro energético y ambiental del país haciendo una excepción a su política actual, instalando un sistema de medición neta ("Net Metering") en la Primera Escuela Ecológica de Puerto Rico. Considerando que la escuela es patrimonio del estado, entendemos que esta concesión de la Autoridad a la Escuela NO debe ser difícil de justificar ni de implantar.

Estamos en espera de una acción positiva por parte de la Autoridad de Energía Eléctrica para que se instale un sistema de medición Neta en la Escuela Ecológica de Culebra y que

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apruebe a Sección 1251, "Net Metering" a la misma vez que adopte las secciones 1252 y 1254, las cuales (su numeración así lo evidencia) están intimamente ligadas.

Preámbulo a la Sección 1254:
La Ley Federal de 2005 obliga a la AEE a considerar adoptar el estandar IEEE 1547 del año 2003 como estandar nacional de interconexion. El propósito del estandar es uniformar el proceso de interconexion entre compañias eléctricas y entre Estados. No obstante toda compañia eléctrica sujeta a PURPA de alguna forma tiene o ha manejado el proceso de interconexion. La fecha de cumplimiento es el 8 de agosto de 2007 para aceptar o no el estandar nacional. De no aceptarlo la AEE debe justificarlo al Federal Energy Regulatory Commission (FERC). Nuevamente y de forma análoga con la sección 1252, la fecha límite para determinar la implantación de la sección 1254 es el 8 de agosto de 2007, menos de un mes a partir del dia de hoy.

Recomendamos el estándar "Interconnection Standards for Distributed Resource"s (Sec. 1254) por las siguientes razones:
Según PURPA desde el año 1978 debe existir una Guía de Interconexión desarrollada por cada Estado. Han pasado casi 20 años desde el inicio de PURPA y muchos de los 50 estados de la nación norteamericana ya han adoptado este estándar nacional para evitar potenciales problemas entre las Compañías que ofrecen el servicio eléctrico ("Utilities") y los Estados. Este estándar se basa, a su vez, en el Estándar 1547 del Institute of Electrical and Electronic Engineers (IEEE) titulado, "Standard for Interconnecting Distributed Resources with Electric Power Systems". El estándar ya está escrito y ha sido puesto a prueba en múltiples Estados. La Autoridad de Energía Eléctrica puede adoptar este estándar fácilmente y es de acceso a todos los profesionales que se involucran en el diseño e instalación de estos sistemas. Según las referencias consultadas (ver al final de esta ponencia) el estándar 1254 permitirá: Aumentar el uso eficiente de combustibles, aumentar la calidad de la electricidad y seguridad de la red de distribución, proveer un servicio más confiable, aplicar generación especializada y mitigar los deficits de generación.
También permitirá: Reducir costos operacionales a la AEE y aus clientes, reducir emisiones y contaminación a nivel global, atender asuntos de Calentamiento Global y de emisiones al ambiente, respaldar la generación por medio de fuentes renovables de energía, atender asuntos de seguridad y a la vez ofrecer mayor seguridad en la estabilidad de los precios de combustible. El mismo abona también a viabilizar el sistema de "Net Metering" en Puerto Rico.

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Endosamos y recomendamos las secciones (1251, 1252 y 1254) que forman parte del Energy Policy Act del año 2005 porque la cantidad de energía que se recibe del sol o del viento no es constante, es intermitente. El consumidor no consume la energía necesariamente en el momento que se genera. Estas medidas le facilitarán a los consumidores recibir el valor completo por la electricidad que producen sin instalar costosos sistemas de almacenamiento en baterías.

Estas secciones también ayudarán a proveer un mecanismo de fácil administración, económico y simple a la vez que ayudará a promover el uso de sistemas alternos de energía tales como generadores eólicos y paneles fotovoltaicos, los cuales proveen importantes beneficios locales, nacionales y globales al ambiente y a la economía.

Casi todos los estados han adoptado estas dos secciones y el sistema de medición neta (Sección 1251). No podemos pensar que Puerto Rico tenga que ser la excepción a la regla. La Autoridad puede demostrar parte de su compormiso con las fuentes alternas de energía, un mejor ambiente y la descentralización de la generación de electricidad en Puerto Rico adoptando estas dos secciones y el sistema de medición neta ahora.

Existe la masa crítica y el deseo de la comunidad profesional, académica y el público general de que Puerto Rico pueda desarrollar su potencial energético utilizando fuentes alternas de energía menos dañinas al ambiente que la actual quema de combustible fósil utilizada por la Autoridad como fuente principal en su proceso de generación.

En resumen recomendamos la adopción no solo de las secciones 1252 y 1254 si no además la sección 1251 ("Net Metering") ahora.

<u>Referencias consultadas en la preparación de esta ponencia</u>:

1. AEE, "Rates and Conditions of Service for Cogenerators and Small Electric Power Producers" , January, 1983.
2. California Energy Comission, "California Interconnection Guidebook: A Guide to Interconnecting Customer-owned Electric Generation Equipment to the Utility Distribution System Using California's Electric Rule 21", September, 2003.
3. Web page: www.dsireusa.org, The Database of State Incentives for Renewable Energy (DSIRE) is a comprehensive source of information on state, local, utility, and selected federal incentives that promote renewable energy.

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4. IEA, Int'l Energy Society, Photovoltaic Power System Programme, "PVPS Annual Report 2004, Implementing Agreement on Photovoltaic Power Systems, 2005.
5. Public utility Policy Act of 1978
6. Energy Policy Act of 2005
7. United States Department of Energy Web Site
8. Federal Energy Regulatory Commission Web Site
9. National Association of Regulatory utility Commission Web Site
10. Trends in Photovoltaic Applications, Report IEA-PVS T1- 14:2005
11. IEEE and UL web pages

Dr. Fernando Abruña, FAIA
PO Box 9022030, San Juan, PR 00902-2030

Representando al:

1. US Green Building Council, Caribbean Chapter
2. American Institute of Architects, Puerto Rico Chapter
3. Colegio de Arquitectos y Arquitectos Paisajistas de Puerto Rico

FIN DE ESTA PONENCIA

Alianza Comunitaria y Ambiental en Acción Solidaria
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10 de julio de 2007

Autoridad de Energia Eléctrica
Ave. Ponce de León, Pda. 16 ½
Santurce, Puerto Rico

Re: **Ponencia de Alianza Comunitaria y Ambiental en Acción Solidaria (ACAAS) sobre Estándares de "EPAct2005"**

Señor Oficial Examinador:

Buenos días. Quien les habla es el Sr. John Miller, representando en esta ocación a la Comisión Coordinadora de la **Alianza de Organizaciones Comunitarias y Ambientales en Acción Solidaria (ACAAS).** Luego de varaios encuentros fraternales para el diálogo y el análisis sobre las necesidades que enfrenta el pueblo puertorriqueño con respecto a el desarrollo comunitario y cuestiones ambientales, hemos organizado dicha Alianza a nivel nacional que tiene como **visión** un Puerto Rico de desarrollo sustentable comunitario, justicia social, y protección ambiental plena; teniendo como eje articulador la dignidad de la persona humana, la conciencia y responsabilidad social, la familia y la nación puertorriqueña.

Además, nuestra **misión** es crear un compromiso integral y participativo de los grupos

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ambientales y comunitarios para lograr efectivamente la elaboración y aplicación de nuevas y mejores leyes protectoras del medioambiente en Puerto Rico.

En este sentido, tenemos como **objetivos generales**: promover que se cumplan las leyes que efectivamente protejen el medioambiente en el país; educar y orientar a las comunidades acerca de temas ambientales; y crear un frente amplio e integral para enfrentar acciones y procesos que amenacen nuestros recursos naturales y la salud de los puertorriqueños.

El sueño propuesto es "un modo de vida sustentable" fruto del cuidado para con todo ser, especialmente para con todas las formas de vida y de responsabilidad colectiva frente al destino común de nuestra tierra y nuestra gente. Asi, la coyuntura histórica que vive Puerto Rico se convierte hoy en un gran desafío que requiere una respuesta urgente desde la más amplia solidaridad.

Como parte de esa gestión solidaria y compromiso social por Puerto Rico, hoy deseamos exponer nuestras ideas, análisis y reclamaciones sobre "EPAct2005".

Las Secciones 1251, 1252 y 1254 de el Subtitulo E de ËPAct2005" enmienda las Secciones 111(d) y 112 del "Public Utility Regulatory Policies Act of 1978 (PURPA)". En el caso de la AEE, estas enmiendas requieren que la AEE considere y determine los siguientes estándares dentro de unas fechas especificas:

- **"Net metering"**
- **"Smart metering"**
- **"Interconnection"**
- **"Utility [AEE] plans to minimize dependence on one fuel source"**
- **"Utility [AEE] 10 year plans to increase efficiency of fossil fuel generation"**

Dichas enmiendas a "PURPA" fomentan el uso eficiente de nuestros recursos

energéticos, inclusive los recursos relacionados a la demanda, donde lo que prevalece son aumentos en precios. "EPAct2005" requiere que la AEE considere maneras especificas de fomentar que sus usuarios conecten generadores de pequeña escala a su red con capacidades de "net" o "advanced metering"; y que permitan que el exceso de electricidad suministrada a su red del generador compense la electricidad extraída de la red por el usuario en otras ocasiones, y por lo tanto, reduzca la cuenta a pagar por el usuario. Esto crea un incentivo adicional económico para que los usuarios de la AEE se conviertan en generadores de energía y así favorecer sus bolsillos.

De no cumplir la AEE con los requisitos de establecer estos estándares, entonces entrara en vigor la Sección 112(c) de "PURPA" que requiere que la consideración y determinación se lleve a cabo con el procedimiento del primer caso de tarifa comenzando después de la fecha limite. Esperamos que los usuarios de la AEE no se vean obligados a utilizar este procedimiento.

A continuación le recordamos a la AEE el horario para considerar y determinar la adopción de los cinco (5) nuevos estándares de "PURPA":

- **"Net metering"** – Comenzar consideración no más tardar 8/8/07, y llegar a determinación no más tardar de 8/8/08.
- **"Smart metering"** – Llegar a determinación no más tardar 8/8/07.
- **"Interconnection"** – Llegar a determinación no más tardar 8/8/07.
- **"Fuel sources"** –Comenzar consideración no más tardar de 8/8/07, y llegar a determinación no más tardar de 8/8/08.
- **"Fossil fuel generation efficiency"** – Comenzar consideración no más tardar 8/8/07, y llegar a determinación no más tardar de 8/8/08.

La Sección 1251 (a)(11) requiere que la AEE provea al ser solicitado los servicios de "net

metering"a cualqluier usuario de la AEE. Efectivo hoy, este servidor le requiere oficialmente a la AEE que le provea el servicio de "net metering". Espero que la AEE responda oficialmente a este requerimiento.

Además, la ACAAS, y este servidor en su carácter personal, le requiere a la AEE el fiel cumplimiento y la implantación de los **estándares de "smart metering" y "interconnection" en el 2007; y los estándares de "net metering", "fuel sources" y "fossil fuel generation efficiency" en el 2008.** Estaremos atentos y pendientes, y de no considerarse e implantarse los cincos (5) estándares se procederá para que se invoque la Sección 112(c) de "PURPA". Nuestro compromiso en este asunto es con todos los sectores de nuestro pueblo, y por lo tanto, actuaremos según sea necesario dentro de nuestro sistema democrático y Constitucional para que se lleve a cabo el fiel cumplimiento de "EPAct2005" en beneficio de todo nuestro pueblo.

Respetuosamente,

John Miller

G00461

10 de Julio del 2007

A:

Autoridad de Energía Energía Eléctrica de Puerto Rico (AEE)
Oficina del Consultor Jurídico
San Juan, PR

De: **Asociación de Consultores y Contratistas de Energía Renovable de Puerto Rico: ACONER-PR**

Ponencia sobre estándares de medición basada en tiempo y comunicación (Sec.1252) y de interconexión (Sec. 1254) según contemplado en el EPACT05

Estimado(a) Oficial Examinador(a),

ACONER-PR es una entidad de reciente creación en el año 2007, fundada con el objetivo principal de fomentar el desarrollo de la energía renovable en Puerto Rico. La Asociación busca a su vez contribuir con el desarrollo de ésta emergente industria en colaboración con agencias de gobierno y otras entidades en términos de política pública sobre el tema De igual manera la ACONER-PR desea desarrollar un ambiente de competencia justa y educar a la Industria, el comercio y el público en general. Bajo esta premisa, se presenta esta ponencia sobre los estándares de medición basada en tiempo y comunicación ("Sec 1252 Time-Based Metering and Communication") y de interconexión ("Sec. 1254. Interconnection Standard For Distributed Resources") según contemplado en la ley federal "Energy Policy Act of 2005" y sujeto a consideración y posible adopción por parte de la AEE.

Antes de comenzar nuestra ponencia sobre el sobre el documento preparado por la División de Estudios y Planificación de la AEE, en su informe publicado en junio del 2007, queremos comentar que es bien importante que se sepa que la Política Pública Energética de PR, establecida en en el 1993 recae sobre el Departamento de Asuntos de Energía. Por ende es bien importante que se defina claramente si este Plan de la AEE se está acatando en conjunto (ó en coordinación) con el Departamento de Asuntos de Energía al igual que se defina como la ley del "Public Utility Regulatory Act" (PURPA) se relaciona con la Política Pública.

A continuación presentamos nuestros comentarios sobre el documento preparado por la División de Estudios y Planificación de la AEE en su informe publicado en junio del 2007:

A - Introducción

En primer lugar queremos aclarar que en la sección posterior a la definición del **"Public Utility Regulatory Act"**, página 2 del reporte, en la sección de **Costo Efectividad** se menciona que "todos los propósitos de PURPA son importantes y se interrelacionan". Pero, en la subsiguiente oración se concluye que: "Cuando se cumplen al menos dos de los tres propósitos se entiende que se alcanzan los propósitos de PURPA". ACONER-PR no está de acuerdo con esta conclusion, pues la misma se presta para que, por ejemplo, la Autoridad decida a tener programas de conservación y de optimización pero no tarifas equitativas. ACONER-PR recomienda que se sustituya la úlima oración diciendo que: "Se deben cumplir con los tres propósitos por los cuales se estableció PURPA en el 1978, para alcanzar objetivos de dicha ley con modificaciones en favor de promover nuevas tecnologías que reduzcan las dependencias de fuentes energéticas fósiles. A su vez, promoviendo reducción de contaminantes hacia el medio ambiente y contribuyendo a la reducción del calentamiento global."

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B – Timed-Based Metering and Communication

ACONER-PR recomienda la adopción del estándar 1252, tal y como lo recomienda la División de Estudios y Planificación de la AEE en su informe publicado en junio del 2007. En el informe la AEE no recomienda que se aplique **en este momento a nivel residencial,** por los costos asociados de infraestructura. El cual penalizaría basado en costos de instalación de nuevos equipos o reemplazo de estos equipos, tanto a el usuario como a la empresa de utilidad ó AEE. Sin embargo, la AEE y **ACONER-PR** sí recomiendan que inicialmente su utilización sea para tarifas Industriales y Comerciales. Finalmente, en clientes con tarifas basada en el Estándar 1252 a través de inyección energética por Fuentes Renovables, se pudiera observar un beneficio tanto para el cliente como para la red AEE, con este tipo de tarifa. **ACONER-PR** favorece la implantación del estandar a nivel residencial en un futuro cercano (posiblemente de 3 a 5 años) una vez se pueda implementar tecnologías costo-efectivas o medidas, subsidios y/o financiamiento que permita absorber los costos para tanto los residenciales como para la AEE. Nuestra organización está totalmente de acuerdo con la adopción de este estándar como un medio importante para ayudar "a fomentar el desarrollo de alternativas de energía renovable".

C - Interconnection Standards for Distributed Resources

ACONER-PR también recomienda la adopción del Estándar 1254, tal y como lo recomienda la División de Estudios y Planificación de la AEE en su informe publicado en junio del 2007. Se incluyen las siguientes recomendaciones que tienen como propósito minimizar preocupaciones relacionadas a temas ya anteriormente cubiertos con los estándares establecidos y ya en práctica en diferentes Estados de los Estados Unidos de Norteamérica:

El Estándar 1547 "DR-Grid Interconnection" de la IEEE se usa para evaluación, especificación, diseño e instalación de los sistemas de generación distribuida. Algunas de las partidas que cubre son:

a. Contribución Corto Circuito
b. Coordinación de Protecciones
c. Regulación de Voltaje
d. Proceso de Isla In intencional "Islanding"
e. Sobre Voltajes y Conexiones a Tierra
f . Situaciones de "Network"

De por sí este Estandar se encaga de cubrir las preocupaciones e inseguridades citadas en las páginas 21 y 22 en las secciones que cubren: 1) Seguridad, 2) Confiabilidad del Sistema, y 3) Operación del Sistema.

También, queremos añadir que, si un cliente residencial, comercial ó industrial se desea interconectar a la red eléctrica con un sistema fotovoltaico, esto sería conforme a un diseño eléctrico según las áreas de relevancia por el Código Eléctrico Nacional; major conocido como el NEC. Ejemplos de ello son:

* Módulos Fotovoltaicos y paneles deben cumplir con el Std UL 1703 "Flat Plate Photovoltaic Modules"
* Inversores, Controladores de Carga deben cumplir con UL 1741
* Diseño de Sistemas e Instalación deben cumplir con:
* IEEE 929 Prácticas Recomendadas para interconexión entre Utilidades y Sistemas Fotovoltaicos
* IEEE 1374 Guías de Seguridad para Sistemas Fotovoltaicos Terrestres
* IEEE 937 Prácticas Recomendadas para sistemas de Baterías en Sistemas Fotovoltaicos ("Lead Acid")
* IEEE 1145 Prácticas Recomendadas para sistemas de Baterías en Sistemas Fotovoltaicos ("Nickel Cadmiun")
* IEC 61215-61646

De igual manera, **ACONER-PR** recomienda la adopción de un Reglamento Técnico y Procesal que fije un sistema de solicitud, evaluación y acuerdo final rápido, fácil y justo para ambas partes (el cliente y la

AEE), a la vez que se asegura la seguridad de las personas envueltas y la integridad del sistema eléctrico. Sólo de esta forma se puede lograr que la adopción de este estatuto se covierta en un paso importante en el desarrollo de la energía renovable en Puerto Rico y no en un impedimento más. Para lograr esto, la **ACONER-PR** recomienda, al igual que la AEE en su informe de junio del 2007, que se adopte un reglamento basado en las guías recomendadas por la "National Association of Regulatory Utility Commissioners" (NARUC) en su informe del 2003 "Model Interconnection Procedures and Agreement for Small Distributed Generation Resources".

A continuación se enfatizan varios puntos fundamentales del estándar de NARUC que nuestra organización considera son de gran importancia para poder lograr los objetivos de rapidez, claridad y justicia para ambas partes:

1. **Recomendamos identificar una agencia reguladora intermediaria que regule y fiscalice los acuerdos entre el "Interconnection Provider" y el "Interconnection Customer".**
2. Recomendamos que se establezca un sistema de solicitud y evaluación con criterios claros y con fechas límites para ambas partes durante todo el proceso ("Super-Expedited Review Process"). Los criterios incluyen el cumplimiento de los equipos de generación a ser interconectados con una serie de códigos y estándares reconocidos en la industria (IEEE, UL, NFPA-NEC, etc.) importantes para asegurar la seguridad de las personas envueltas y la integridad del sistema de distribución eléctrica.
3. Recomendamos que se establezca un proceso de evaluación alterno para estudiar la viabilidad de interconexión, de un sistema que no cumpla con los criterios del proceso inicial.
4. Sugerimos que se establezcan formas de aplicaciones claras, sencillas y divididas en dos clasificaciones de sistemas de generación (menor de 20 KV y mayor de 20 KV).
5. Solicitmaos un acuerdo final entre ambas partes por medio de un "Contrato de Interconexión".
6. **ACONER-PR** busca el establecimiento de cuotas justas y basadas en los costos reales incurridos por la AEE durante el proceso de solicitud y evaluación.

Nuevamente, nuestra organización, **ACONER-PR** enfatiza en la creación de un proceso justo que fomente (no retarde) el desarrollo de las fuentes de energía renovable en la Isla.

Sin otro particular quedamos de ustedes.

Cordialmente,

Representantes de la **ACONER-PR:**

Ing Ernesto Rivera,PE
Renewable Solutions Engineering

Ing Walter Pedreira,PE
Caribbean Renewable Technologies

Dr Albith Colon, PE
Energtech

Sr Lino Aponte
La Casa Solar

cc:
Dr. Javier Velez Arocho, Secretario del Departamento de Recursos Naturales y Ambientales de PR
Dr. Javier Quintana, Administración de Asuntos de Energia
Colegio de Ingenieros y Agrimensores de Puerto Rico
Asociación de Constructores de Hogares de PR
Departamento de Ingenieria Electrica y Computadoras, UPR-RUM, Mayagüez
Universidad ___________________
Colegio de Arquitectos de Puerto Rico
Concilio Green Building, Capítulo de Puerto Rico

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Ponencia del Ing. Juan Antonio Pérez González
Presidente
Colegio de Ingenieros y Agrimensores
De Puerto Rico

Ante el Tribunal Administrativo de la Autoridad de Energía Eléctrica (**AEE**), presidido por el Oficial Examinador en Audiencia Pública celebrada el 10 de junio del 2007.

Re.: *Energy Policy Act 2005* (**EPAct2005**), PL 109-58 y *Public Utility Regulatory Policies Act* (**PURPA**), PL 95-617

RESUMEN EJECUTIVO

El Energy Policy Act 2005 (EPAct 2005) requiere la consideración de una serie de estándares que están relacionados y que en conjunto pueden adelantar significativamente los propósitos de PURPA. Al presente la AEE está considerando dos de estos estándares, el de interconexión y el de medición inteligente.

El Colegio de Ingenieros y Agrimensores de Puerto Rico (CIAPR) respalda la adopción del estándar de interconexión y nos alegramos que la AEE esté dispuesta a dar este primer paso. En específico, recomendamos la adopción del estándar IEEE-1547 así como los estándares de NARUC que atienden todas las preocupaciones mencionadas por la AEE en su informe de *Consideración de los Estándares del EPAct 2005 (Time Based Metering and Communications Interconnection Standards for Distributed Resources).*

Además, la AEE debe atender los siguientes puntos:

- La AEE debe dejar establecidos los requerimientos de medición para la interconexión, así como el precio y demás términos y condiciones para la compra del excedente de electricidad producido por los generadores distribuidos.

- La AEE debe dejar establecido el arbitraje como alternativa para la resolución de disputas sobre interconexión. A tales efectos, sugerimos que se utilice el recurso de expertos técnicos o "*Technical Masters*" sugeridos por NARUC.

- La AEE debe adoptar el procedimiento expedito de interconexión para facilidades de generación pequeñas certificadas no mayores de 10KW y basadas en inversores que ha adoptado el FERC.

El último punto es particularmente importante ya que dicho procedimiento es el que aplicaría a los abonados residenciales que son el 91% de los abonados de la AEE.

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El CIAPR también entiende que el segundo estándar de medición inteligente constituye el próximo paso importante para adelantar los propósitos de PURPA y que debe hacerse el esfuerzo de adoptar una o más de las opciones que el EPAct 2005 requiere considerar.

Sin embargo, la AEE no ha mostrado los datos específicos necesarios que requiere la consideración de dicho estándar y no estamos de acuerdo con que se excluya a los abonados residenciales de todas las opciones. El EPAct 2005 requiere la evaluación individual de cada una de las alternativas de medición para cada una de las clases de servicio. Entendemos que esa evaluación detallada debe llevarse a cabo de forma que se adopten las opciones más apropiadas a tenor con dicha evaluación en conformidad con PURPA y la Ley 83.

El Colegio de Ingenieros y Agrimensores de Puerto Rico está en la mejor disposición de ayudar a la AEE a cumplir a cabalidad con los requisitos del EPAct 2005 y a completar una evaluación adecuada de este segundo paso tan importante. Como un paso en la dirección positiva el Colegio ha comenzado a considerar los elementos necesarios para instalar un proyecto fotovoltaico en su propiedad que sirva para...

- Demostrar e ilustrar a sus miembros sobre la madeja de repercusiones económicas – deseables e indeseables -, y sobre los beneficios ambientales y de salud pública que traen ésta y otras tecnologías renovables.
- Guiar a instituciones hoy en precario (hospitales, escuelas, etc.) a sobrevivir los actuales costos de energía.
- Ilustrar a los Honorables miembros de las ramas Ejecutiva y Legislativa del Gobierno de Puerto Rico sobre opciones tecnológicas maduras para explotar económicamente fuentes de energía nativa, inagotable y limpia, a tenor con las Leyes #83 del 2 de mayo del 1941 y #128 del 29 de junio del 1977 que constituyeron a la Autoridad de Energía Eléctrica (AEE) y a la Administración de Asuntos de Energía (AAE), respectivamente.

Sometemos para el record el Informe del CIAPR que recoge las recomendaciones antes discutidas y urgimos nuevamente a la Autoridad de Energía Eléctrica a considerar el conjunto de los estándares de EPAct 2005 a los efectos de que se implante una sana política pública energética en Puerto Rico.

■

Ponencia del Ing. Juan Antonio Pérez González
Presidente
Colegio de Ingenieros y Agrimensores
De Puerto Rico

Ante el Tribunal Administrativo de la Autoridad de Energía Eléctrica (**AEE**),
presidido por el Oficial Examinador en Audiencia Pública celebrada el 10 de junio del 2007.

Re.: *Energy Policy Act 2005* (**EPAct2005**), PL 109-58 y *Public Utility Regulatory Policies Act* (**PURPA**), PL 95-617

Señoras y Señores,

Conforme a la Ley que lo creó, Ley #319 del 15 de mayo del 1938 según enmendada, el *Colegio de Ingenieros y Agrimensores de Puerto Rico* (**Colegio**), que agrupa alrededor de 12,000 colegiados e interviene en estos procedimientos administrativos por medio de su Presidente, Ing. Juan Antonio Pérez González, Licencia Núm. 6709 quien, para mayor sencillez, en los sucesivo les hablará en primera o tercera persona, y ahora presento copia escrita de mi ponencia al Oficial Examinador aquí presente (HAGO ENTREGA para record).

Acorde con lineamientos regulatorios del Colegio y con los propósitos de este procedimiento, cito algunos trozos del Reglamento vigente como sigue:

Fines

ARTÍCULO 2 - El Colegio tendrá como fines principales los siguientes:
a) **Fomentar el bienestar de la comunidad**;
b) **Contribuir al adelanto y defensa de las profesiones de ingeniería y agrimensura**, y;
c) **Propender al mejoramiento del ejercicio profesional y al bienestar de sus miembros.**

Facultades y Deberes

ARTICULO 3 - Conforme a los fines anteriormente señalados y a las facultades y derechos conferidos por ley, corresponde a este Colegio:

a) **Velar por los intereses y bienestar de la comunidad Puertorriqueña**;
b) **Salvaguardar y proteger los derechos de sus miembros en todo lo que se refiere al ejercicio de su profesión**;
c) Colaborar con la Asamblea Legislativa y las Agencias de Gobierno en lo relativo a la reglamentación del ejercicio de la ingeniería y de la agrimensura;
d) Promover y establecer relaciones con instituciones profesionales, nacionales y extranjeras, que persigan fines similares;

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e) **Asesorar al Estado en asuntos de su competencia**;
f) Promulgar y poner en vigor Cánones de Ética Profesional;
g) **Promover el progreso de** la cultura, **la ciencia y la tecnología, especialmente en lo relativo a la ingeniería, a la agrimensura y a las artes e industrias auxiliares**;
h) **Promover el** embellecimiento y **mejoramiento ambiental de la comunidad puertorriqueña**;
i) **Pronunciarse en torno a cuestiones de interés público en aquellos asuntos que se consideren de su competencia**;...

Intervención del Colegio

En ánimo constructivo, del que luego daré muestra, hago la siguiente presentación:

Trasfondo

Cada país suele tener su propio ciclo económico en función de los productos de sus respectivas economías; pero aquellas que viertan fracciones importantes de sus productos al comercio internacional normalmente se comportan vinculadas. En conjunto, hace ya muchos trimestres que la economía de Latinoamérica está dando muestras claras de resurgimiento. En América Latina hoy no hay un solo país cuya economía no haya crecido durante el 2006 en relación al 2005, incluso Cuba y Haití (al menos según cifras oficiales del Banco Mundial).[1] Este no es el caso de Puerto Rico, no obstante sus estrechos vínculos comerciales con las economías más poderosas de la Tierra.

Todas las economías del mundo se mueven con energía de un tipo u otro. Casi todos los países de Latinoamérica tienen recursos energéticos nativos (Haití es un caso aparte, pues ya han agotado la casi totalidad de su leña, pero les quedan viento y sol).

Puerto Rico tiene al menos cuatro recursos naturales autóctonos: viento, sol, caudal hidráulico y biomasa. La Ley #83 (ley constitutiva de la *Autoridad de Fuentes Fluviales*, hoy la *Autoridad de Energía Eléctrica*; **AEE**), según enmendada, reformada y suplementada, les obliga a conservar, desarrollar, utilizar y aprovechar los recursos fluviales de PR con el fin de proporcionarle al Pueblo de PR – en la forma económica más amplia – los beneficios de aquellas.[2] La Sección 6 de esta ley concede todos los derechos y poderes

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[1] **CNN en Español**; 6 de Julio del 2007.
[2] **Ley #83** del 2 de mayo del 1941; Secc. 6.

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necesarios para llevar a cabo los propósitos y su inciso (l) reza: "*Determinar, fijar, alterar, imponer y cobrar tarifas razonables... por el uso o servicios... suministrados por [la AEE]...; Disponiéndose, que al fijar tarifas... y otros cargos por energía eléctrica, la [AEE]* ***tendrá en cuenta aquellos factores que conduzcan a fomentar el uso de la electricidad en la forma más amplia y variada que sea económicamente posible...*** " (**Énfasis provisto**).

La Secc. 22 (a) de esta misma ley reza "Por la presente se resuelve y declara que la [AEE] **se crea para los fines de la conservación de los recursos naturales**,..." (**énfasis provisto**).

Enlaces

Por lo antes dicho, la antes aludida[2] Ley #83, según enmendada, y particularmente la Sección 196c de su Reglamento, se relacionan directamente con las bases legales para una estructura tarifaria como la que se propone en este procedimiento.

Igualmente se relacionan, entre otros, las siguientes Leyes, según enmendadas, y sus correspondientes Reglamentos:

- Ley #128 del 29 de junio del 1977.
- Ley #21 del 31 de mayo del 1985.
- Ley #170 del 12 de agosto del 1988 ("**LPAU**").
- PURPA 16 USCA § 2623b #2 (*Automatic Adjustment Clauses*) y 16 USCA § 2625, entre otras secciones.
- Etc.

Postura de la AEE y Comentarios

La AEE ha declarado su intención, o inclinación, a adoptar el estándar de la *Sección 1254 Interconnection Standards for Distributed Resources* y a no adoptar el estándar de la Sección 1252 *Time-Based Metering and Communications* para abonados residenciales. Esta es la posición expresada en el documento titulado "CONSIDERACIÓN DE LOS ESTÁNDARES DEL EPAct2005: *TIME-BASED METERING AND COMMUNICATIONS INTERCONNECTION STANDARDS FOR DISTRIBUTED RESOURCES*" preparado por la División de Planificación y Estudios de la AEE con fecha junio de 2007 ("**Consideración 2007**"). A continuación expresamos opinión sobre cada una de estas intenciones.

Sección 1254 Interconnection Standards for Distributed Resources

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Aplaudimos la intención de la AEE de adoptar el estándar de la *Sección 1254 Interconnection Standards for Distributed Resources.* La AEE menciona en su "Consideración" que el reglamento que finalmente se adopte debe cumplir *"con las normas, reglamentos y estándares aplicables, incluyendo el estándar IEEE 1547."* Además, recomendamos que, al diseñar los procedimientos y acuerdos de interconexión, la Autoridad considere los modelos establecidos en las guías de *NARUC.* No obstante, la Autoridad deberá armonizar los procedimientos establecidos en estas guías con sus procesos administrativos.

Es de suma importancia que, al momento de producir el reglamento de interconexión, el mismo describa un proceso ágil y sencillo de interconexión a la red eléctrica que permita al pequeño productor comenzar a producir energía en un período corto. Que el mismo cumpla con los estándares aceptables de interconexión sin inclusión de requisitos adicionales o especiales que encarezcan el sistema o su operación. Además, solicitamos la oportunidad de participar en la creación de este reglamento de interconexión.

Estándares de Interconexión para Recursos de Generación Dispersa (o Distribuida)

A. Disposiciones del *EPAct 2005* sobre Interconexión

La Sección 1254 del Subtítulo E del EPAct 2005 establece un estándar de interconexión y requiere que se determine su adopción o no en o antes del 8 de agosto de 2007. Dicho estándar conlleva hacer disponible al consumidor de servicio eléctrico, una vez solicitado, el servicio de interconexión para conectar un recurso de generación eléctrica distribuida ubicado en su propiedad a las facilidades de distribución de la AEE. La adopción del estándar requiere:

- Ofrecer servicios de interconexión basados en los estándares técnicos desarrollados por el Instituto de Ingenieros Electricistas y Electrónicos ("IEEE" por sus siglas en inglés) y en particular el *IEEE Standard 1547 for Interconnecting Distributed Resources with Electric Power Systems* ("IEEE 1547") según éste sea enmendado de tiempo en tiempo.

- Adoptar procedimientos y acuerdos para que los servicios provistos promuevan las mejores prácticas de interconexión para generación distribuida, incluyendo las prácticas establecidas en códigos modelo adoptados por asociaciones de agencias reglamentarias estatales tales como el *Nacional Association of Regulatory Utility Commissioners*

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("NARUC"). Los mismos deben ser justos, razonables y no crear preferencias o trato discriminatorio injustificado.

B. Criterios de Evaluación

1. PURPA

El estándar de interconexión debe analizarse a tenor con los propósitos de la ley federal PURPA de 1978, según enmendada, que incluye fomentar:

(a) la conservación de energía suplida por las compañías de electricidad,

(b) el uso más eficiente de las instalaciones y recursos de producción de energía eléctrica y

(c) la implementación de tarifas equitativas para los consumidores de electricidad.

2. Consideraciones adicionales identificadas por la AEE

Las siguientes consideraciones adicionales fueron identificadas por la AEE como relevantes a la determinación sobre la adopción del estándar de interconexión que incluyen evitar:

(a) el riesgo a la seguridad que pueda representar la condición, conocida como isla eléctrica o *islanding*.

(b) que se afecte la confiabilidad del Sistema por la aportación de corriente adicional de corto circuito que deba interrumpirse ante condiciones de fallas eléctricas en el sistema de distribución.

(c) Evitar problemas operacionales en los alimentadores de la AEE como el parpadeo, distorsión harmónica del voltaje, problemas de regulación de voltaje y sobrevoltaje durante condiciones de averías.

C. Evaluación del Estándar de Interconexión

1. PURPA

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Una evaluación favorable bajo PURPA no requiere que se promuevan todos sus propósitos. Solamente se requiere que cualquiera de los propósitos se cumpla sin que los demás se vean negativamente afectados.[3] En este caso, entendemos que todos los propósitos de PURPA se cumplen.

El primer propósito, dirigido hacia la conservación, se cumple a cabalidad. Los clientes interconectados con la AEE con generación propia podrán suplir toda o parte de su carga eléctrica durante ciertos periodos de tiempo e incluso contribuir el exceso de la energía producida. A corto plazo tales instalaciones disminuirían el aumento en demanda aunque no necesariamente producirán una disminución en la demanda eléctrica. Ciertamente, para lograr una reducción en demanda pudiera requerirse la instalación de miles de sistemas pequeños distribuidos y son pocos los estados que han logrado tal grado de aceptación. Ello hace necesaria la implantación inmediata de este estándar incluyendo los procedimientos expeditos recomendados por NARUC para pequeños generadores distribuidos.

El segundo propósito de PURPA, dirigido a la eficiencia, incluye técnicas que favorezcan el uso de recursos de mayor disponibilidad en Puerto Rico sobre el uso de recursos importados.[4] Claramente, la adopción de un estándar interconexión promueve el uso de fuentes de energía renovables como la solar y la eólica, que permiten reducir la dependencia en el petróleo. Entendemos la conclusión preliminar de la AEE relativa a que "*la compañía tendrá que construir y mantener su sistema para suplir todas las cargas, incluyendo aquellas que normalmente se suplen con generación propia*", pero discrepamos del alegado análisis de la AEE, ya que convenientemente pasan muy por alto tales beneficios como la evitaciones de gastos de combustible multiplicadas por el factor de pérdidas de T & D, precisamente a las horas cuando la AEE despacha sus unidades más costosas o - en su defecto - sus "*peaking units*" (peor aún), además de que pasa por alto las correspondientes emisiones ambientales evitadas.

Finalmente, concurrimos con la conclusión en el informe preliminar que la interconexión de generadores al sistema de distribución tiene el potencial de promover tarifas equitativas. Sin embargo, ello requiere que la AEE establezca precios razonables para el auspicio de generación con tecnología renovable producida en exceso.

2. Evaluación de consideraciones adicionales identificadas por la AEE

[3] Véase "***Reference Manual and Procedures for Implementation of the PURPA Standards in the Energy Policy Act of 2005***" de 22 de marzo de 2006, Página 15.
[4] Ibid., Páginas14-15.

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Las consideraciones adicionales que se discuten en el informe preliminar de la AEE van dirigidas a aspectos de seguridad y confiabilidad en la operación del sistema eléctrico. En este sentido, el informe preliminar de la AEE reconoce que el IEEE1547 surge de un propósito de "desarrollar un estándar que proveyera una metodología uniforme para los servicios de interconexión, que estableciera los requisitos técnicos mínimos para lograr una interconexión segura y confiable al sistema de distribución eléctrica."

Por otro lado, el informe preliminar especifica que los aspectos adicionales identificados deben considerarse en atención a la configuración radial del sistema de distribución de la Autoridad. En este sentido, debe señalarse que el procedimiento adoptado por NARUC atiende la distribución radial y establece distintos grados de análisis dependiendo de la naturaleza de la interconexión.

Por ejemplo, el procedimiento expedito desarrollado por NARUC establece un primer escrutinio que tiene como condiciones:

- Que la generación agregada, incluyendo la interconexión propuesta, conectada al circuito radial no exceda el 5% de la demanda pico total.

- Que la generación agregada, incluyendo la interconexión propuesta, no contribuya más del 10% a la corriente de falla del circuito de distribución.

- Que la generación agregada, incluyendo la interconexión propuesta, no exceda el 85% de la capacidad de interrupción de corto circuitos.

Cuando no se dan las condiciones para un procedimiento expedito, NARUC reconoce la necesidad de estudios adicionales para determinar la viabilidad de la interconexión.

Por otro lado, en el caso de los sistemas distribuidos más pequeños que pueden representar la instalación típica de los abonados residenciales o el 91% de los abonados de la AEE, apoyamos el procedimiento expedito desarrollado recientemente por el *Federal Energy Regulatory Commission* (**FERC**) para facilidades de generación pequeñas certificadas no mayores de 10KW y basadas en inversores. Dicho procedimiento facilita aún más la interconexión de estas facilidades pequeñas cuyo impacto sobre la red se considera mínimo. Véase Anejo.

Por consiguiente, entendemos que el estándar de interconexión evaluado atiende las preocupaciones de la AEE con respecto a la seguridad y confiabilidad del sistema eléctrico.

D. Recomendaciones

Acogemos la recomendación preliminar de la AEE para que se adopte el estándar de interconexión bajo EPAct 2005, incluyendo tanto el estándar IEEE 1547como el *NARUC Model Interconection Procedures and Agreement for Small Distributed Generation Resources.*

Sin embargo, como parte de la adopción de los procedimientos y acuerdo de interconexión de NARUC deben atenderse los siguientes puntos.

- La AEE debe dejar establecidos los requerimientos de medición para la interconexión, así como el precio y demás términos y condiciones para la compra del excedente de electricidad producido por los generadores distribuidos.

- La AEE debe dejar establecido el arbitraje como alternativa para la resolución de disputas sobre interconexión. A tales efectos, sugerimos que se utilice el recurso de expertos técnicos o "*Technical Masters*" sugeridos por NARUC.

- La AEE debe adoptar el procedimiento expedito de interconexión para facilidades de generación pequeñas certificadas no mayores de 10KW y basadas en inversores que ha adoptado el FERC.

Entendemos que las anteriores sugerencias sirven para actualizar y armonizar los procedimientos establecidos en las guías de NARUC a los procesos administrativos de la AEE.

Sugerimos la creación de una estructura de colaboración entre la AEE y los abonados para producir este reglamento, y nos ponemos a la disposición del funcionario a cargo de esta tarea en la AEE para viabilizar esta colaboración.

Nos interesa sobremanera participar en la creación de este reglamento, así como en la definición de un proceso ágil y sencillo de interconexión a la red eléctrica que permita al pequeño productor comenzar a producir energía en un período corto. Este es el primer paso para que la AEE y sus abonados puedan cosechar los beneficios mutuos que hoy brinda la mejor tecnología disponible para la *medición neta*.

000477

También solicitamos la oportunidad de participar en la consideración que la AEE está obligada a hacer de la *Sección 1251 Net Metering and Additional Standards* bajo *EPAct 2005*, a cumplirse en o antes del 6 de agosto de 2008 ("**Consideración 2008**"). A la vista de la tercera disminución consecutiva en la tasa de incremento anual del consumo, registrada por la AEE (2004, 2005 y 2006)[5], todos los abonados al servicio de la AEE debieran tener mucho interés que la misma se adopte, aunque no se les ha brindado una franca oportunidad para enterarse de los cuestionamientos o para manifestarse sobre ellos. Una estructura de colaboración entre la AEE y los abonados para considerar la medición neta y crear el reglamento que la regirá, sería un ejercicio muy saludable y mejor sintonizado con los tiempos que vivimos; tiempos donde los abonados aspiramos a mayor participación que la que se ofrece, por ejemplo, en estas vistas. Nuevamente, nos ponemos a la disposición del funcionario a cargo de esta tarea en la AEE para viabilizar esta colaboración.

Sección 1252 *Time-Based Metering and Communications*

En lo que respecta a la Sección 1252 *Time-Based Metering and Communications*, la AEE se inclina por no adoptar este estándar. Sin embargo, ni en la "Consideración 2007", ni en los documentos relacionados que la AEE nos ha mostrado en reunión celebrada el 05 de julio del 2007, aparece un análisis profundo que sustente esta decisión.

Son múltiples las ventajas de ofrecer medición y facturación, basada en el intervalo de tiempo de consumo y creemos que el asunto amerita mayor consideración y posible adaptación para los clientes residenciales. A continuación presentamos algunas de estas ventajas.

En su informe titulado "*Assessment of Demand Response and Advanced Metering*" el FERC define el concepto de medición avanzada o "*advanced metering*" de esta manera (traducida al Español):

> "*Medición avanzada es un sistema de medición que registra el consumo del cliente, y posiblemente otros parámetros, cada hora o más frecuentemente, y que provee para transmitir este registro diariamente, o más frecuentemente, a un centro de recolección de datos usando una red de comunicaciones.*"

El concepto fundamental en la definición de medición avanzada envuelve mucho más que un metro capaz de medir en intervalos frecuentes. La medición

[5] *Thirty-third Annual Report on the Electric Property of the PREPA; Washington Group International, June 2006.*

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avanzada se refiere a la medición, red de comunicaciones y al sistema de recolección y de procesamiento de datos. Esta infraestructura se conoce como la infraestructura de medición avanzada. En nuestra opinión, el espíritu del mandato de *EPAct2005* es precisamente el desarrollo y utilización de esta infraestructura de medición avanzada para "...*economically meet growing demand or to defer construction or upgrades of generation or distribution*".[6]

La medición avanzada apoya el uso de tarifas basadas en hora de uso ("*time of use*"; **TOU** por sus siglas en el Inglés) de forma moderna y creativa, acorde con lo estipulado en la citada Ley #83 que creó la hoy AEE. La medición avanzada permite mejorar el servicio que ofrece la compañía de electricidad al cliente, reducir el robo de electricidad detectando intervenciones con el sistema, permite monitorear la calidad del servicio eléctrico al cliente, mejora el manejo de apagones, mejora el pronóstico de la demanda y la gestión/manejo de los equipos de la compañía generadora, identificando con precisión la carga a servir por una línea de distribución o por transformador específico. Este último punto permite que la compañía de electricidad escoja la capacidad de los equipos a utilizar en forma más eficiente y económica.

El uso de medición avanzada permite un mejor manejo de asuntos de importancia económica, tanto para los abonados al servicio de electricidad como para la AEE. La planificación de futuros incrementos de capacidad, el manejo de la demanda punta, el manejo de la vegetación y un mejor monitoreo de los niveles de voltaje en los puntos de interconexión con los clientes son ejemplos de ello. La AEE no analiza a fondo ninguna de estas ventajas en su "Consideración 2007".

Otra oportunidad de la medición avanzada es que provee información automatizada al abonado con la que puede manejar su propio consumo. Por ejemplo, el enviarle señales de precio a controladores de temperatura inteligentes, termostatos inteligentes, que ajusten la temperatura de sistemas de aire acondicionado para clientes residenciales con aire central o a clientes comerciales y/o industriales.

El informe preliminar "Consideración 2007" confunde, porque en el alegado análisis, la AEE usa una sola curva de demanda agregada (la suma de la demanda de todos los clientes) para caracterizar todo día del año aunque sabemos que en sus operaciones la AEE usa una curva para domingo, otra para sábado, otra para viernes, otra para lunes y una quinta curva para martes, miércoles y jueves. Además, aunque la curva de demanda agregada utilizada

[6] ***Assessment of Demand Response and Advanced Metering**, Staff Report, **FERC** Docket AD 06-2-000; Aug. 2006,* Page 70.

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fuera el promedio de las anteriores la misma es muy pobre en su resolución de demanda. A pesar de que no existe demanda agregada por debajo de unos 2,300 MW la curva tiene el rango en el eje vertical comenzando en cero (0) MW impidiendo apreciar los detalles de los cambios de la demanda según pasa el tiempo.

Otro asunto que nos causa confusión es el cómputo de una demanda base (cantidad a ser suplida por unidades base o de menor costo) no de 2,300 MW como muestra la curva de demanda sino de 3,074 MW, cantidad muy cercana a la demanda pico de alrededor de 3,600 MW. Creemos que las conclusiones del alegado análisis de la AEE carecen de lógica ya que pasan por alto el hecho que en la realidad, el despacho está afectado por muy conocidas y muy crónicas limitaciones en el sistema de T & D y, por tanto, lo que se pretende derivar a partir de la alegada determinación de demanda máxima de 3,074 MW, resulta "*non-sequitur*".

También resulta confuso el llamado costo de generación para el 2009 entre 7 y 9 ¢/kWh que se presenta sin justificación alguna excepto, que se alega resulta del uso de un programa computadorizado. ¿Si el costo de generación en el 2009 será de unos 9 centavos, porqué a nivel residencial hoy pagamos unos 19 centavos por kilovatio hora?

Igualmente sucede con la conclusión del alegado estudio de carga de tres subestaciones mayormente residenciales. En ese caso la AEE concluye, "según la gráfica", que la demanda máxima de los clientes residenciales ocurre dentro del ("en el") período pico del sistema de la AEE, alegación que convenientemente pasa muy por alto precisamente las ventajas que hoy brinda la generación dispersa (DG v. CG) junto a la métrica de "*real-time billing*" con la mejor tecnología, así como el hecho que la captación de energía solar igualmente ocurrirá precisamente durante las horas pico de las demandas comercial e industrial.

En realidad no se pueden evaluar adecuadamente sus alegadas conclusiones, pues no tenemos acceso alguno a los datos usados para hacer los supuestos cómputos. Esta es, en nuestra opinión, la falla fundamental de todo este proceso, el proceso de la creación de la "Consideración", vano asidero que usa la AEE para justificar su decisión y el proceso de esta vista pública, en franca violación con la letra y espíritu de la citada Ley #83, según enmendada.

La AEE es un monopolio gubernamental regulado por sí mismo, es decir, no-regulado por terceros. Creemos que con la tal auto-regulación se puede cumplir cabalmente con la letra y espíritu de la citada Ley #83, según enmendada, solamente si se siguen los estrictos lineamientos de la mejor práctica de

000480

conservación de energía estipulada en la Ley Federal PURPA del 1978 y su Reglamento, según respectivamente enmendados, en coincidencia con los demás estatutos mencionados en la Pág. 3 de esta ponencia (**Enlaces**).

Queremos aprovechar la ocasión para señalar, además, que en Puerto Rico no existe agencia alguna que atienda reclamos de los abonados en apelación tocante a lo que respecta obtener de la AEE mejor servicio, transparencia o garantías de excelencia en el desempeño de los servicios al cliente. Si algún abonado tuviera alguna queja contra la AEE la única opción práctica es acudir a un Tribunal de Justicia y confiar que una rama del Gobierno no proteja la otra.

Sugerimos que no se abandone la consideración de medición avanzada por los beneficios de conservación y mejoras al servicio que recibe el cliente que esta medición puede traer. En consideración al EPAct 2005, la consideración de este estándar debe incluir un análisis individual para cada clase de servicio y tipo de medición.

Consideraciones Finales: Costos de Energéticos v. Costos de Electricidad

La AEE basa sus proyecciones financieras a plazo medio en predicciones de la *Energy Information Administration* (**EIA**) del *US Department of Energy* (**US DOE**).[7] En el contexto de la geopolítica que rige el precio de los energéticos fósiles,[8] creemos que el ya tradicional empleo de estas predicciones pudiera resultar desatinado, particularmente en el caso de una isla como Puerto Rico.

[7] ***Thirty-Third Annual Report on the Electric Property of the Puerto Rico Electric Power Authority**, June 2006*; Page 46 y Appendix I.
[8] Particularmente a partir del 11 de septiembre del 2001.

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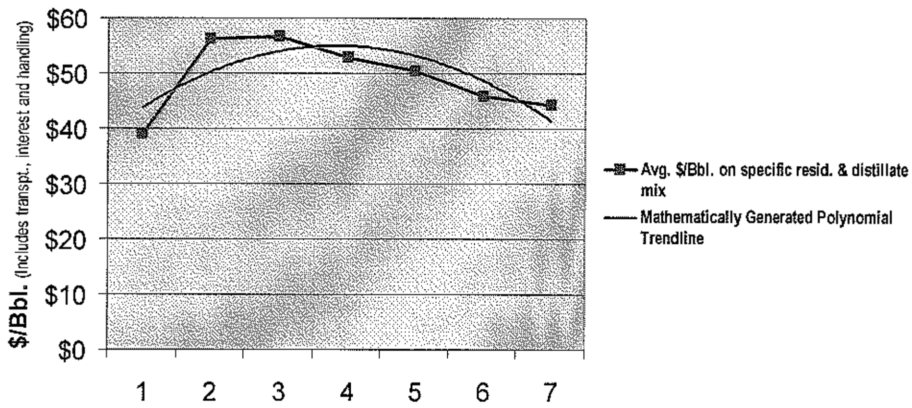
Average PREPA Historical Fuel Cost

for Electricity Generation and Projections

(Years 2005 to 2011)



Source: *33rd Annual Report on the Electric Property*
Washington Group International; June, 2006

Visualizar la cordura de este llamado a la cautela requiere, al menos, tomar en cuenta y analizar varios eventos recientes; en orden cronológico:

- En ocasión de su última comparecencia ante los delegados al Foro Mundial de las Naciones Unidas,[9] el Presidente *Hugo Chávez* vaticinó que los precios mundiales del crudo seguirían subiendo, en lugar de estabilizarse, y que podrían llegar a $100/Barril en los próximos dos años.
- El Gobierno del Presidente *Mahmoud Ahmadinejad* anunció[10] que Irán probó por segunda véz con éxito un torpedo capáz de zurcar bajo el agua a 223 MPH. El anuncio de *Tehran* advirtió que ningún submarino o barco de guerra podrá escapar del torpedo, aunque lo detectasen, dada su velocidad bajo el agua.
- El Presidente *Hugo Chávez* acaba de regresar de Rusia, donde se reunió con su homólogo *Vladimir Putin*. *El Universal*, un diario de Venezuela, informó que *Chávez* colocó un pedido a Rusia de nueve (9) submarinos armados para uso con miras hacia Puerto Rico.[11]

Aunque el vaticinio de precios del crudo que hizo el Presidente *Chávez* aún no se haya cumplido, no hay que ser clarividente para adivinar complicidad con sus homólogos de Iran y Rusia. Esta percepción no necesariamente sugiere que los

[9] ***60th General Assembly of the United Nations***; New York, 15th September, 2005.
[10] http://www.military.com/NewsContent/0,13319,93060,00.html?ESRC=topstories.RSS; 3rd April, 2006.
[11] ***S.J. Star***, 26 de junio del 2007.

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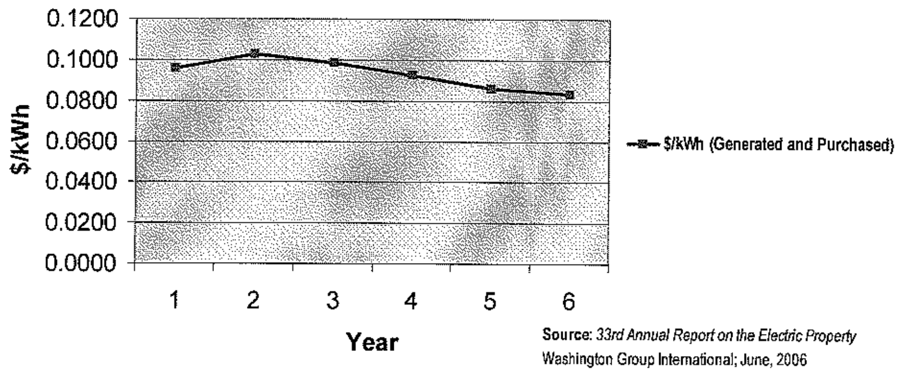
Presidentes *Chávez* o *Ahmadinejad* pretendan usar esas armas contra los EEUU o Puerto Rico; más bien las usarían para atizar los precios del crudo.

Average PREPA Thermal Energy Prices
(Years 2006 to 2011)



Source: *33rd Annual Report on the Electric Property*
Washington Group International; June, 2006

Nótese que los costos promedio del kWh que surgen de las proyecciones a plazo medio de la AEE (ver gráfica)[3] se basaron en el logro de una optimización[12] de las tasas calóricas de todas sus plantas antes del 2011, así como en una benigna proyección del costo de la resultante ensalada de combustibles (ver gráfica). Ahora bien, si se analizan estas proyecciones de la EIA en el actual contexto geopolítico, se comprenderá que cualquier incremento en el precio del crudo causará consecuencias desastrosas e irreversibles a la economía Puertorriqueña y a la AEE.

Razonamientos, Conclusiones y Recomendaciones Finales

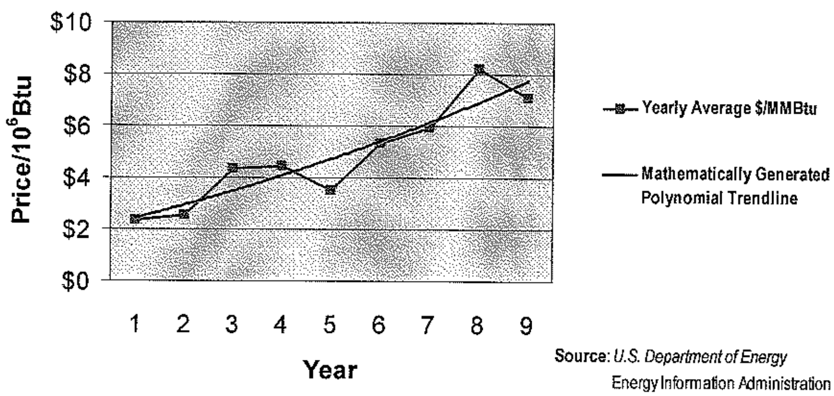
Recordando las tan frecuentemente citadas palabras de *George Santillana* (filósofo Español de mediados del s. XX): *"Aquellos que no aprendan de los errores de la historia, estarán condenados a vivirla de nuevo."...*

- Un incremento sostenido en el precio del crudo eventualmente causará aumentos en los costos de todos los demás energéticos fósiles (aceite residual, destilados, gas natural, carbón, etc.).[13]

[12] Vide #3 *supra*; Appendix IV.

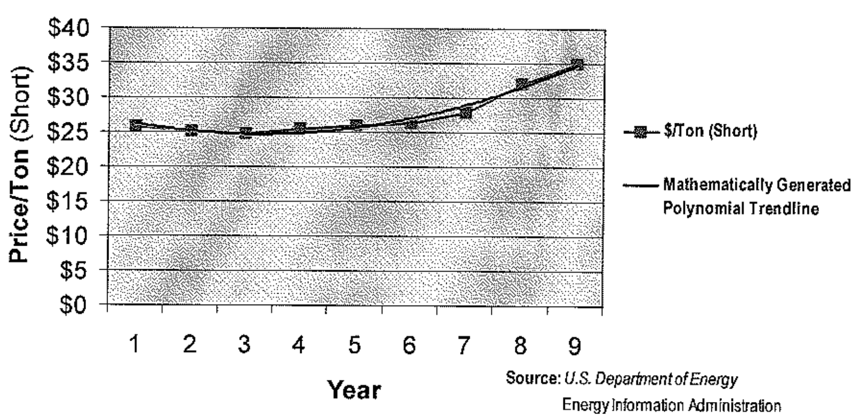
[13] La razón es que el mercado reconoce y paga el valor de un energético por millón de BTUs en aquellos casos en que los combustibles se se consideren limpios.

US Natural Gas Prices for Electricity Generation
(Last nine years: 1998 to 2006)



- Una postura injustificadamente resistiva al *"net metering"* por la AEE impulsará aún más reacciones conservadoras[14] que podrían llevar algunos abonados hacia el tipo de facilidades *"stand alone"*. Estas facilidades tienden a ser permanentes, y su posible despliegue inevitablemente traería lamentables resultados para el flujo de caja de la AEE.
- Cualquier aumento sostenido en el costo del kWh en PR mejorará la viabilidad económica de aquellas alternativas con tecnologías renovables libres de contaminación y de costos de combustible y que, por tanto, igualmente tienden a ser permanentes.

US Steam Coal Prices for Electricity Generation
(Last nine years: 1998 to 2006)



[14] De parte de algunos abonados hacia la conservación, cogeneración y renovables.

- Una descontrolada adopción de tecnologías de conservación y de renovables por una gran masa de abonados, causará en la AEE muchos de los efectos indeseables que causa el aumento de abonados a tarifas subsidiadas, incluyendo más presiones hacia la inequidad tarifaria y reducción en el flujo de caja.
- Contemplando lo vivido a partir del bloqueo de la Organización de Países Exportadores de Petróleo (**OPEP**) en el 1973-'74, la AEE tiene que reconocer que, precisamente porque es isla, Puerto Rico está más expuesto que los EEUU a las repercusiones estratégicas y económicas que inescapablemente se derivan de extremos incontrolables en la geopolítica mundial.
- Por tanto, las tecnologías de conservación de energía, de cogeneración y de renovables traen beneficios económicos del lado de la demanda. **Pero hay que tener en cuenta que sus respectivas tasas de adopción deben hacerse de forma graduada**, si es que se quiere mantener la salud financiera de la AEE junto con la viabilidad económica de Puerto Rico.
- La ausencia de una política energética coherente ya trajo consecuencias deplorables tanto para la economía de Puerto Rico, como para la AEE.[15] Resulta penoso tomar conciencia de que esto se pudo haber evitado, si la Administración de Asuntos de Energía (**AAE**) hubiese cumplido prudente y sabiamente con la Ley #128 del 29 de junio del 1977 y si la AEE hubiese acatado los lineamientos de política pública energética de Puerto Rico, ausentes desde diciembre del 1993.
- Por tanto, como parte de su respuesta a los razonamientos que anteceden, el Colegio ha comenzado a considerar los elementos necesarios para instalar un proyecto fotovoltaico en su propiedad que sirva para...
    - Demostrar e ilustrar a sus miembros sobre la madeja de repercusiones económicas – deseables e indeseables -, y sobre los beneficios ambientales y de salud pública que traen ésta y otras tecnologías renovables.
    - Guiar a instituciones hoy en precario (hospitales, escuelas, etc.) a sobrevivir los actuales costos de energía.
    - Ilustrar a los Honorables miembros de las ramas Ejecutiva y Legislativa del Gobierno de Puerto Rico sobre opciones tecnológicas maduras para explotar económicamente fuentes de energía nativa, inagotable y limpia, a tenor con las Leyes #83 del 2 de mayo del 1941 y #128 del 29 de junio del 1977 que

[15] El Gobernador de Puerto Rico, Honorable Aníbal Acevedo Vilá, dijo ante la Cámara de Comercio reunida en Fajardo, que el costo de la energía era uno de diez (10) "retos" que restringen el desarrollo económico de PR (***S.J. Star***, 23 de junio del 2007).

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constituyeron a la Autoridad de Energía Eléctrica (AEE) y a la Administración de Asuntos de Energía (AAE), respectivamente.

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Puerto Rico Electric Power Authority - Public Hearing of July 10, 2007
Consideration of Time-Based Metering and Communications
Interconnection Standards for Distributed Resources

Hector Arana - Electricity Consumer - Ave. E. Pol 407 Suite 390
San Juan, Puerto Rico 00926 - Tel. (787) 731-0610

My name is Hector Arana, residential electric consumer of the Puerto Rico Electric Power Authority, Account No. 01405304170019. At 10:39 AM of July 9, 2007 I presented hand written request to participate in this Hearing to PREPA. (Exhibit 1: Copy of Hand Written Request to Participate)

In the event that no opposition is presented, I will proceed with my participation in this Public Hearing is as a **Formal Intervenor** pursuant **16 USC § 2631. Intervention in proceedings**

(a) Authority to intervene and participate

In order to initiate and participate in the consideration of one or more of the standards established by subchapter II of this chapter or other concepts which contribute to the achievement of the purposes of this chapter, the Secretary, any affected electric utility, or any ***electric consumer*** of an affected electric utility may ***intervene and participate as a matter of right*** in any ratemaking proceeding or other appropriate regulatory proceeding relating to rates or rate design which is conducted by a State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by a nonregulated electric utility.

(b) Access to information

Any intervenor or participant in a proceeding described in subsection (a) of this section ***shall have access to information available to other parties to the proceeding*** if such information is relevant to the issues to which his intervention or participation in such proceeding relates. Such information may be obtained through reasonable rules relating to discovery of information prescribed by the State regulatory authority (in the case of proceedings concerning electric utilities for which it has ratemaking authority) or by the nonregulated electric utility (in the case of a proceeding conducted by a nonregulated electric utility).

The most important aspect of this Public Hearing is the applicability of the Laws of the Commonwealth of Puerto Rico to **16 U.S.C. § 2623. (PURPA SECTION 113) Adoption of certain standards**

(a) Adoption of standards

Not later than two years after November 9, 1978, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall provide public notice and conduct a hearing respecting the standards established by subsection (b) of this section and, on the basis of such hearing, shall—

(1) adopt the standards established by subsection (b) of this section (other than paragraph (4) thereof) if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate to carry out the purposes of this chapter, is otherwise appropriate, and is consistent with otherwise applicable State law, and

(2) adopt the standard established by subsection (b)(4) of this section if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate and consistent with otherwise applicable State law.

000488

For purposes of any determination under paragraphs (1) or (2) and any review of such determination in any court in accordance with section 2633 of this title, the purposes of this chapter supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any such standard, pursuant to its authority under otherwise applicable State law. (Exhibit 2: Public Utility Regulatory Policies Act - PL 95-617 - 16 USC 2601 et seq.)

The applicable Laws of the Commonwealth of Puerto Rico to this Public Hearing are the following:

1- Act No. 128 of June 29, 1977 Section 1. Public Policy on Energy

The Commonwealth's Public Policy on Energy shall be based on the following basic principals, among others;

(b) To obtain the lowest possible energy cost for our society.

(f) To adopt a "Puerto Rico Energy Conservation Plan". This plan shall be established pursuant to applicable federal regulations.

(g) To promote, in coordination with the agencies mentioned in Section 9 scientific studies to provide Puerto Rico with alternate energy sources, which will contribute substantially to our economic growth by helping us to obtain a greater degree of self-sufficiency in energy matters. Special attention shall be given to solar energy and its associated sources, among others. (Exhibit 3: Act No. 128 of June 29, 1977 Public Policy on Energy)

2 - Puerto Rico Electric Power Authority Act - Law No. 83 of May 2, 1941, 22 L.P.R.A. § 196 Powers of the Authority (Exhibit 4: Puerto Rico Law No. 83 of May 2, 1941, 22 L.P.R.A. § 196 (c))

The Authority is created for the purpose of conserving, developing, and utilizing, and aiding in the conservation, development, and utilization of water and energy resources of Puerto Rico, (...)

(c) *to prescribe, adopt, amend and repeal bylaws and regulations governing the manner in which its general business may be conducted* (...) *The bylaws so adopted shall have force of law once the provisions of § § 1041 to 1059 of Title 3 are complied with*. (Puerto Rico Law No. 170 of August 12, 1988, Uniform Administrative Procedure Act of Puerto Rico.

3 - Puerto Rico Law No. 170 of August 12, 1988, 3 L.P.R.A. § 2121 *Whenever the agency proposes to adopt, amend or repeal a rule or regulation it shall publish a notice in a newspaper of general circulation in Puerto Rico. The notice shall contain a summary or brief explanation of the purpose of the proposed action; a reference to the legal provision that authorizes such action,* (...) *and where the complete text of the regulations to be adopted will be available to the public.* **3 L.P.R.A. § 2127 (a)** *A rule or regulation approved after the effective date of this act shall be null if it does not substantially meet the provisions of this chapter.* (Exhibit 5: Puerto Rico Law No.170 of August 12, 1988)

000489

4 - Governing Board of PREPA - Resolution No. 1756 - April 23, 1981

(Exhibit 6: Board of PREPA - Resolution No. 1756 - April 23, 1981)

POR CUANTO: La Ley Federal PURPA (P.L. 95-617) de 1978 establece que las compañias de electricidad deben ***implantar programas de conservacion de energia*** a traves de la promocion de proyectos de ***cogeneracion y de produccion de electricidad en pequeña escala, asuntos que reglamenta la Comision Federal Reguladora de Energia (FERC)*** mediante la Orden Num. 69.

POR CUANTO: La reglamentacion adoptada por ***FERC estipula que las compañias de electricidad estableceran tarifas para la compra de electricidad*** desarrolladas en base a costo evitado ("avoided cost"); adoptaran, mediante el proceso de vistas publicas, un plan para implantar procedimientos que respondan a la relglamentacion del FERC; y proveeran informacion sobre costos a los proponentes de estos tipos de proyectos, entre otras cosas.

POR CUANTO: La Junta de Gobierno de la Autoridad de Energia Electrica, ***en armonia con la politica publica del Gobierno de Puerto Rico, tambien reconoce los meritos de estas alternativas de conservacion de energia***.

POR TANTO: La Junta de Gobierno de la Autoridad de Energia Electrica resulve:

1. Implantar, con vigencia inmediata, las tarifas de cogeneracion y aplicables tambien a pequeños productores de electricidad que se describen en el Exhibit I.

2. **Adoptar con vigencia inmediata la reglamentacion sobre estos asuntos que se describen en el Exhibit II.**

3. Incluir la consideracion de estas ***tarifas*** y el plan mencionados en la Agenda de las Vistas Publicas en que se trataran los ***6 estandares tarifarios de PURPA***, que se celebraran proximamente.

5 - Governing Board of PREPA - Resolution No. 1830 - January 21, 1983

(Exhibit 7: Resolution No. 1830 - January 21, 1983)

6 - Governing Board of PREPA - Resolution No. 2748 - January 26, 1999

(Exhibit 8: Resolucion No. 2748 - January 26, 1999)

In contrast with the above laws and Resolutions of the Governing Board of PREPA, regarding Interconnection Standards, it becomes clear that the actions taken by the PREPA to not permit the Interconnection of Renewable Energy Technologies to its power generation and distribution system and the conduct of this Public Hearing are ***Ultra Vires*** and outside of ***Reasonableness.*** Chrysler Corp. v. Brown, 441 U.S. 281, 302 (1970), Stark v. Wickard, 321 U.S. 288, 309-310 (1944), Meade Township v. Andrus 695 F.2d 1006 (6th Cir. 1982), Kelly V. Zamarello, 486 P.2d 906, 911 (Alaska 1971), Citizens to Save Spencer County v. EPA, 600 F.2d 844, 873 (D.C. Cir. 1979)

The subject-matter of the hearing is highly technical and complex to be properly discussed in two (2) hearings lasting only four (4) hours each and the participants be only provided fifteen (15) minutes to present their views regarding the matter without having a opportunity to ask questions and receive answers from PREPA.

The Authority appointed "**multidisciplinary working committees**" to study the aspects to be evaluated (mentioned on Page 1 in Paragraph 2) and the Authority has not provided such documented information to the electric consumers and to the participants of the hearing.

The Authority has not provided documented information to the electric consumers and to the participants of these hearings regarding the recommendations, as to any necessary or advisable revisions of rates and charges, that Washington Group International, Consulting Engineers of PREPA, has provided to the Authority regarding the subject-matter of these Public Hearings, under the provision of Section 706 of Article VII of the Trust Indenture Agreement, dated as of January 1, 1974, as amended and supplemented, between the Authority and U.S. Bank Trust National Association, the successor Trustee for the 1974 Trust Agreement.

Upon review of the information, "Cost of Generation Cents per kwh", provided by PREPA, on page 16 of the document, Consideration of Time-Based Metering and Communications Interconnection Standards for Distributed Resources, the subject-matter of this Public Hearing, I find such information to be nonfactual, in contrast with documented information provided in Annual Reports prepared by Washington Group International, Consulting Engineers of PREPA, during the past decade.

I have, since July 1, 2003, following exactly PREPA Interconnection Regulations, tried to obtain a permit to install a small residential wind turbine battery charging system. (Exhibit 9: Copy of Letter dated July 1, 2003 from Mr. Hector Arana to Miss Yolanda Ramos)

At this moment PREPA continues to obstruct permitting the installation of the small wind turbine system installation. (Exhibit 10 Copy of letter dated April 20, 2007 from Mrs. Yoamarie Figueroa to Mr. Hector Arana)

In the late afternoon of July 9, 2007 I received a fax from Mrs. Sonia Miranda Vega, PREPA Official, regarding my request of being provided copy of documented information pertinent to this Public hearing. (Exhibit 11: Copy of fax letter from Mrs. Sonia Miranda Vega to Mr. Hector Arana)

I will procure the documented information regarding the EPRI document and other information pertinent to these public hearings during the next ten (10) days. I have planned to present additional written comments to PREPA regarding the subject-matter of these hearing withing the time frame of July 15 and July 27, 2007.

Thank you for allowing me to participate as Intervenor in this Public Hearing.

I am prepare to answer any questions that the Examiner has.

Hector Arana

Hector Arana

000491

July 9, 2007

Felix Perez Rivera, Esq.
Office of "Juridico" - Puerto Rico Electric Power Authority
Puerto Rico Electric Power Authority
San Juan, P. R.

EXHIBIT - 1

I, Hector Arana, Electric Rate Payer, request opportunity to participate in Public Hearing of July 10, 2007 regarding EPACT05: Sec. 1252 and Sec. 1254 STANDARDS, as a Formal Intervenor.

I also request to be provided information indicated in PREPA Proposal of "Consideración de los Estándares del EPACT 2005: Time-Base Metering and Communications Interconnection Standards for Distributed Resource (June-2007).

The information is the following, as indicated on Page 1 of the Proposal of PREPA, prepared by División de Planificación y Estudios:

1- The documentation used by the "Work Committee" appointed by the Authority to study such regulations and the "Work Committee" recomendations

2- Copy of EPRI International Report regarding "Interconnection Standards for Distributed Resources."

Thank you
Hector Arana

000492

EXHIBIT- 2

CHAPTER 46—PUBLIC UTILITY REGULATORY POI

CROSS REFERENCES

Grants to nonregulated electric utilities to carry out duties and resp under this chapter, see 42 USCA § 6807.

LIBRARY REFERENCES

Law Review and Journal Commentaries

PURPA from coast to coast: America's great electricity experiment. O'Callaghan & Steve Greenwald, 10 Nat.Resources & Env't I 1996).

000493

Notes of Decisions

1. Constitutionality

Congressional findings which underlay this chapter, i.e., that the regulated activities have an immediate effect on interstate commerce and that protection of public health, etc. required a program for increased conservation of electric energy and increased more efficient use of facilities, have a rational basis. F. E. R. C. v. Mississippi, U.S.Miss.1982, 102 S.Ct. 2126, 456 U.S. 742, 72 L.Ed.2d 532, rehearing denied 103 S.Ct. 15, 458 U.S. 1131, 73 L.Ed.2d 1401.

2. Questions for Congress

Even if this chapter will not significantly improve the nation's energy situation, congressional findings underlying this chapter compel conclusion that the means chosen are reasonably adapted to the ends permitted by U.S.C.A. Const. Art. 1, § 8, cl. 3; and it is not for the judiciary to say where the means chosen represent the wisest choice as it is sufficient that Congress was not irrational in concluding that limited federal regulation of retail sales of electricity and natural gas and of relationships between cogenerators and electric utilities was essential to protect interstate commerce. F. E. R. C. v. Mississippi, U.S.Miss.1982, 102 S.Ct. 2126, 456 U.S. 742, 72 L.Ed.2d 532, rehearing denied 103 S.Ct. 15, 458 U.S. 1131, 73 L.Ed.2d 1401.

3. Law governing—Generally

Nothing in the text or history of Public Utility Regulatory Policies Act (PURPA) suggests Congressional intent to grant exclusive federal question jurisdiction over state law claims that may involve or implicate PURPA. Grays Ferry Cogeneration Partnership v. PECO Energy Co., E.D.Pa.1998, 998 F.Supp. 542.

Fact that federal statute established applicable standards for qualified facility (QF) certification, violations of which by Chapter 11 debtor-cogenerator gave rise to adversary proceeding by purchaser of power for breach of power purchase agreement (PPA), did not mean that federal law privileges, rather than state law privileges applied in discovery dispute, where establishing whether debtor met QF standards was item of proof culminating in state law claim, i.e., violation of PPA. In re Megan-Racine Associates, Inc., Bkrtcy.N.D.N.Y.1995, 189 B.R. 562.

4. —— Choice of law, law governing

Under New York's autonomy principle, bankruptcy court would honor parties' choice of law in power purchase agreement (PPA) insofar as matters of substantive law were concerned in dispute arising out of whether Chapter 11 debtor-cogenerator violated provisions of PPA by falling below required quality facility (QF) standards. In re Megan-Racine Associates, Inc., Bkrtcy.N.D.N.Y.1995, 189 B.R. 562.

5. Jurisdiction

Action in which cogeneration partnership and its members sought preliminary injunction prohibiting partnership's primary customer from breaching and terminating its power purchase agreements, and compelling customer to pay rates set forth in agreements and file application for approval of agreements under Pennsylvania statute, did not arise under federal law for jurisdictional purposes; while plaintiffs had cited Public Utility Regulatory Policies Act (PURPA), their claims were traditional state law tort and contract claims and did not turn on federal law, and PURPA did not preempt application of state law. Grays Ferry Cogeneration Partnership v. PECO Energy Co., E.D.Pa.1998, 998 F.Supp. 542.

§ 2602. Definitions

As used in this Act, except as otherwise specifically provided—

(1) The term "antitrust laws" includes the Sherman Antitrust Act (15 U.S.C. 1 and following), the Clayton Act (15 U.S.C. 12

000494

and following), the Federal Trade Commission Act (15 U.S.C. 14 [41] and following), the Wilson Tariff Act (15 U.S.C. 8 and 9), and the Act of June 19, 1936, chapter 592 (15 U.S.C. 13, 13a, 13b, and 21A).

(2) The term "class" means, with respect to electric consumers, any group of such consumers who have similar characteristics of electric energy use.

(3) The term "Commission" means the Federal Energy Regulatory Commission.

(4) The term "electric utility" means any person, State agency, or Federal agency, which sells electric energy.

(5) The term "electric consumer" means any person, State agency, or Federal agency, to which electric energy is sold other than for purposes of resale.

(6) The term "evidentiary hearing" means—

(A) in the case of a State agency, a proceeding which (i) is open to the public, (ii) includes notice to participants and an opportunity for such participants to present direct and rebuttal evidence and to cross-examine witnesses, (iii) includes a written decision, based upon evidence appearing in a written record of the proceeding, and (iv) is subject to judicial review;

(B) in the case of a Federal agency, a proceeding conducted as provided in sections 554, 556, and 557 of Title 5; and

(C) in the case of a proceeding conducted by any entity other than a State or Federal agency, a proceeding which conforms, to the extent appropriate, with the requirements of subparagraph (A).

(7) The term "Federal agency" means an executive agency (as defined in section 105 of Title 5).

(8) The term "load management technique" means any technique (other than a time-of-day or seasonal rate) to reduce the maximum kilowatt demand on the electric utility, including ripple or radio control mechanisms, and other types of interruptible electric service, energy storage devices, and load-limiting devices.

(9) The term "nonregulated electric utility" means any electric utility other than a State regulated electric utility.

(10) The term "rate" means (A) any price, rate, charge, or classification made, demanded, observed, or received with respect to sale of electric energy by an electric utility to an electric consumer, (B) any rule, regulation, or practice respecting any

000495

such rate, charge, or classification, and (C) any contract pertaining to the sale of electric energy to an electric consumer.

(11) The term "ratemaking authority" means authority to fix, modify, approve, or disapprove rates.

(12) The term "rate schedule" means the designation of the rates which an electric utility charges for electric energy.

(13) The term "sale" when used with respect to electric energy includes any exchange of electric energy.

(14) The term "Secretary" means the Secretary of Energy.

(15) The term "State" means a State, the District of Columbia, and Puerto Rico.

(16) The term "State agency" means a State, political subdivision thereof, and any agency or instrumentality of either.

(17) The term "State regulatory authority" means any State agency which has ratemaking authority with respect to the sale of electric energy by any electric utility (other than such State agency), and in the case of an electric utility with respect to which the Tennessee Valley Authority has ratemaking authority, such term means the Tennessee Valley Authority.

(18) The term "State regulated electric utility" means any electric utility with respect to which a State regulatory authority has ratemaking authority.

(19) The term "integrated resource planning" means, in the case of an electric utility, a planning and selection process for new energy resources that evaluates the full range of alternatives, including new generating capacity, power purchases, energy conservation and efficiency, cogeneration and district heating and cooling applications, and renewable energy resources, in order to provide adequate and reliable service to its electric customers at the lowest system cost. The process shall take into account necessary features for system operation, such as diversity, reliability, dispatchability, and other factors of risk; shall take into account the ability to verify energy savings achieved through energy conservation and efficiency and the projected durability of such savings measured over time; and shall treat demand and supply resources on a consistent and integrated basis.

(20) The term "system cost" means all direct and quantifiable net costs for an energy resource over its available life, including the cost of production, distribution, transportation, utilization, waste management, and environmental compliance.

1992, see section 1 of Pub.L. 102–486, set out as a Short Title note under section 13201 of Title 42, The Public Health and Welfare.

Amendments

1992 Amendments. Subsec. (b). Pub.L. 102–486, § 111(c), set forth separate time limitations in the case of standards under pars. (7), (8), and (9) of section 2621(d).

CROSS REFERENCES

Procedural requirements for consideration and determination of rate standards established by state regulatory authority or nonregulated electric utility, see 16 USCA § 2621.

LIBRARY REFERENCES

American Digest System

Electricity ⇐1.

Key Number System Topic No. 145.

Encyclopedias

Electricity, see C.J.S. § 1.

WESTLAW ELECTRONIC RESEARCH

See WESTLAW guide following the Explanation pages of this volume.

§ 2623. Adoption of certain standards

(a) Adoption of standards

Not later than two years after November 9, 1978, each State regulatory authority (with respect to each electric utility for which it has ratemaking authority), and each nonregulated electric utility, shall provide public notice and conduct a hearing respecting the standards established by subsection (b) of this section and, on the basis of such hearing, shall—

(1) adopt the standards established by subsection (b) of this section (other than paragraph (4) thereof) if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate to carry out the purposes of this chapter, is otherwise appropriate, and is consistent with otherwise applicable State law, and

(2) adopt the standard established by subsection (b)(4) of this section if, and to the extent, such authority or nonregulated electric utility determines that such adoption is appropriate and consistent with otherwise applicable State law.

For purposes of any determination under paragraphs (1) or (2) and any review of such determination in any court in accordance with section 2633 of this title, the purposes of this chapter supplement otherwise applicable State law. Nothing in this subsection prohibits any State regulatory authority or nonregulated electric utility from making any determination that it is not appropriate to adopt any

000497

such standard, pursuant to its authority under otherwise applicable State law.

(b) **Establishment**

The following Federal standards are hereby established:

(1) **Master metering**

To the extent determined appropriate under section 2625(d) of this title, master metering of electric service in the case of new buildings shall be prohibited or restricted to the extent necessary to carry out the purposes of this chapter.

(2) **Automatic adjustment clauses**

No electric utility may increase any rate pursuant to an automatic adjustment clause unless such clause meets the requirements of section 2625(e) of this title.

(3) **Information to consumers**

Each electric utility shall transmit to each of its electric consumers information regarding rate schedules in accordance with the requirements of section 2625(f) of this title.

(4) **Procedures for termination of electric service**

No electric utility may terminate electric service to any electric consumer except pursuant to procedures described in section 2625(g) of this title.

(5) **Advertising**

No electric utility may recover from any person other than the shareholders (or other owners) of such utility any direct or indirect expenditure by such utility for promotional or political advertising as defined in section 2625(h) of this title.

(c) **Procedural requirements**

Each State regulatory authority (with respect to each electric utility for which it has ratemaking authority) and each nonregulated electric utility, within the two-year period specified in subsection (a) of this section, shall (1) adopt, pursuant to subsection (a) of this section, each of the standards established by subsection (b) of this section or, (2) with respect to any such standard which is not adopted, such authority or nonregulated electric utility shall state in writing that it has determined not to adopt such standard, together with the reasons for such determination. Such statement of reasons shall be available to the public.

(Pub.L. 95–617, Title I, § 113, Nov. 9, 1978, 92 Stat. 3123.)

000408

Greater Cleveland Welfare Rights Organization, Inc. v. Public Utilities Com'n of Ohio, Ohio 1982, 442 N.E.2d 1288, 2 Ohio St.3d 62, 2 O.B.R. 619.

5. Evidentiary hearing requirement

State regulatory authority complies with this section relating to lifeline rates when it holds an evidentiary hearing to evaluate whether lifeline rates should be implemented. Greater Cleveland Welfare Rights Organization, Inc. v. Public Utilities Com'n of Ohio, Ohio 1982, 442 N.E.2d 1288, 2 Ohio St.3d 62, 2 O.B.R. 619.

A contested case hearing pursuant to R.L.H. 1955, Supp.1981, § 91-9, at which extensive evidence was presented, in which appellant consumer advocates fully participated, and in which detailed findings of fact and conclusions of law were entered, satisfied requirement of "evidentiary hearing" under subsec. (b) of this section providing for adoption of lifeline electric rates. Application of Hawaiian Elec. Co., Inc., Hawai'i 1983, 669 P.2d 148, 66 Haw. 538.

6. Burden of proof

Consumer advocates who intervened in review of electric company rate increase seeking establishment by state Public Utilities Commission of lifeline rates under this section were parties initiating administrative proceeding investigating adoption of these rates and, as such, had burden of proof. Application of Hawaiian Elec. Co., Inc., Hawai'i 1983, 669 P.2d 148, 66 Haw. 538.

§ 2625. Special rules for standards

(a) Cost of service

In undertaking the consideration and making the determination under section 2621 of this title with respect to the standard concerning cost of service established by section 2621(d) (1) of this title, the costs of providing electric service to each class of electric consumers shall, to the maximum extent practicable, be determined on the basis of methods prescribed by the State regulatory authority (in the case of a State regulated electric utility) or by the electric utility (in the case of a nonregulated electric utility). Such methods shall to the maximum extent practicable—

(1) permit identification of differences in cost-incurrence, for each such class of electric consumers, attributable to daily and seasonal time of use of service and

(2) permit identification of differences in cost-incurrence attributable to differences in customer demand, and energy components of cost. In prescribing such methods, such State regulatory authority or nonregulated electric utility shall take into account the extent to which total costs to an electric utility are likely to change if—

(A) additional capacity is added to meet peak demand relative to base demand; and

(B) additional kilowatt-hours of electric energy are delivered to electric consumers.

(b) Time-of-day rates

In undertaking the consideration and making the determination required under section 2621 of this title with respect to the standard

for time-of-day rates established by section 2621(d)(3) of this title, a time-of-day rate charged by an electric utility for providing electric service to each class of electric consumers shall be determined to be cost-effective with respect to each such class if the long-run benefits of such rate to the electric utility and its electric consumers in the class concerned are likely to exceed the metering costs and other costs associated with the use of such rates.

(c) Load management techniques

In undertaking the consideration and making the determination required under section 2621 of this title with respect to the standard for load management techniques established by section 2621(d)(6) of this title, a load management technique shall be determined, by the State regulatory authority or nonregulated electric utility, to be cost-effective if—

(1) such technique is likely to reduce maximum kilowatt demand on the electric utility, and

(2) the long-run cost-savings to the utility of such reduction are likely to exceed the long-run costs to the utility associated with implementation of such technique.

(d) Master metering

Separate metering shall be determined appropriate for any new building for purposes of section 2623(b)(1) of this title if—

(1) there is more than one unit in such building,

(2) the occupant of each such unit has control over a portion of the electric energy used in such unit, and

(3) with respect to such portion of electric energy used in such unit, the long-run benefits to the electric consumers in such building exceed the costs of purchasing and installing separate meters in such building.

(e) Automatic adjustment clauses

(1) An automatic adjustment clause of an electric utility meets the requirements of this subsection if—

(A) such clause is determined, not less often than every four years, by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or by the electric utility (in the case of a nonregulated electric utility), after an evidentiary hearing, to provide incentives for efficient use of resources (including incentives for economical purchase and use of fuel and electric energy) by such electric utility, and

(B) such clause is reviewed not less often than every two years, in the manner described in paragraph (2), by the State regulatory authority having ratemaking authority with respect to

000500

such utility (or by the electric utility in the case of a nonregulated electric utility), to insure the maximum economies in those operations and purchases which affect the rates to which such clause applies.

(2) In making a review under subparagraph (B) of paragraph (1) with respect to an electric utility, the reviewing authority shall examine and, if appropriate, cause to be audited the practices of such electric utility relating to costs subject to an automatic adjustment clause, and shall require such reports as may be necessary to carry out such review (including a disclosure of any ownership or corporate relationship between such electric utility and the seller to such utility of fuel, electric energy, or other items).

(3) As used in this subsection and section 2623(b) of this title, the term "automatic adjustment clause" means a provision of a rate schedule which provides for increases or decreases (or both), without prior hearing, in rates reflecting increases or decreases (or both) in costs incurred by an electric utility. Such term does not include an interim rate which takes effect subject to a later determination of the appropriate amount of the rate.

(f) Information to consumers

(1) For purposes of the standard for information to consumers established by section 2623(b)(3) of this title, each electric utility shall transmit to each of its electric consumers a clear and concise explanation of the existing rate schedule and any rate schedule applied for (or proposed by a nonregulated electric utility) applicable to such consumer. Such statement shall be transmitted to each such consumer—

(A) not later than sixty days after the date of commencement of service to such consumer or ninety days after the standard established by section 2623(b)(3) of this title is adopted with respect to such electric utility, whichever last occurs, and

(B) not later than thirty days (sixty days in the case of an electric utility which uses a bimonthly billing system) after such utility's application for any change in a rate schedule applicable to such consumer (or proposal of such a change in the case of a nonregulated utility).

(2) For purposes of the standard for information to consumers established by section 2623(b)(3) of this title, each electric utility shall transmit to each of its electric consumers not less frequently than once each year—

(A) a clear and concise summary of the existing rate schedules applicable to each of the major classes of its electric consumers for which there is a separate rate, and

000501

(B) an identification of any classes whose rates are not summarized.

Such summary may be transmitted together with such consumer's billing or in such other manner as the State regulatory authority or nonregulated electric utility deems appropriate.

(3) For purposes of the standard for information to consumers established by section 2623(b) (3) of this title, each electric utility, on request of an electric consumer of such utility, shall transmit to such consumer a clear and concise statement of the actual consumption (or degree-day adjusted consumption) of electric energy by such consumer for each billing period during the prior year (unless such consumption data is not reasonably ascertainable by the utility).

(g) Procedures for termination of electric service

The procedures for termination of service referred to in section 2623(b) (4) of this title are procedures prescribed by the State regulatory authority (with respect to electric utilities for which it has ratemaking authority) or by the nonregulated electric utility which provide that—

(1) no electric service to an electric consumer may be terminated unless reasonable prior notice (including notice of rights and remedies) is given to such consumer and such consumer has a reasonable opportunity to dispute the reasons for such termination, and

(2) during any period when termination of service to an electric consumer would be especially dangerous to health, as determined by the State regulatory authority (with respect to an electric utility for which it has ratemaking authority) or nonregulated electric utility, and such consumer establishes that—

(A) he is unable to pay for such service in accordance with the requirements of the utility's billing, or

(B) he is able to pay for such service but only in installments,

such service may not be terminated.

Such procedures shall take into account the need to include reasonable provisions for elderly and handicapped consumers.

(h) Advertising

(1) For purposes of this section and section 2623(b) (5) of this title—

(A) The term "advertising" means the commercial use, by an electric utility, of any media, including newspaper, printed matter, radio, and television, in order to transmit a message to a

000502

Energy Office—Advisory Committee on Energy; Creation

(H.B. 358)

[No. 128]

[*Approved June 29, 1977*]

AN ACT

To establish the bases on which the Public Policy of Puerto Rico regarding the energy problem shall be framed, to create an Advisory Committee on Energy and to set forth its objectives, to create the Energy Office, to define its purposes, powers, organization and its interaction with the other government organizations, to authorize the Governor to take the necessary measures to protect the health of the People of Puerto Rico in a state of emergency, to transfer equipment, materials and personnel, to impose penalties to enforce the law, to appropriate funds, to repeal Act No. 4 of July 9, 1973, as amended, and for other purposes.

Statement of Motives

Of all the primary sources of energy, oil has constituted the basis of our energy system. At present, Puerto Rico has no other source of energy which can contribute substantially to its social and economic development. As a result, imports of oil and its by-products continue playing a fundamental role in our economy. However, the most recent development in the energy field, at the United States as well as at the international level, points to the real and effective possibility of developing alternate sources of energy which may provide significant quantities to satisfy our energy needs. It is desirable, on behalf of our security as a people, that we explore and exploit these new possibilities to the greatest possible extent. At the same time, it is necessary that we implement optimization and conservation policies of all energy resources.

To attain this purpose, Puerto Rico should have an institution to integrate and coordinate at government level, all those functions related to the energy problem which are at present scattered throughout different government agencies and dependencies. Besides channelling the maximum efforts in such direction, this institution could consider our energy situation in an integral con-

text, as well as its particular interrelation with our social and economic development.

It is imperative for Puerto Rico to formulate and maintain a public policy on energy that may be coherent and based on medium and long-term perspectives covering the whole energy sector and relating to it to the socioeconomic development goals of the country.

Although marketing mechanisms may be basic elements of the energy policy of a country, whether it has natural resources or not, the vital importance of energy supplies and the structural changes of the relationship between the supply and demand thereof, have induced the governments not to depend exclusively on these mechanisms, and they have had to participate, directly and indirectly, to obtain, attend to and guarantee the most desirable development of the energy sector within reason, thus achieving the goals of their public policy on this matter.

In view of this situation, the Legislature of the Commonwealth of Puerto Rico has decided to create, attached to the Office of the Governor, the Puerto Rico Energy Office, which shall integrate at government level, all those programs related to energy matters, and shall be empowered to carry out studies, research, compilation and coordination of information on the energy fossil-fuel sector, as well as on alternate energy sources to satisfy the needs of our people and to regulate, whenever necessary, those relevant aspects which may adversely affect the Island's energy supplies. This Office shall be the Governor's principal advisory body on energy matters.

An Energy Advisory Committee is also provided, which shall serve conjointly with this Office as liaison with the different sectors of our society, providing independent technical advice.

Be it enacted by the Legislature of Puerto Rico:

Section 1.—Public Policy on Energy—

The Commonwealth's Public Policy on Energy shall be based on the following basic principles, among others:

(a) To guarantee the availability of energy supplies to the country at all times.

(b) To obtain the lowest possible energy costs for our society.

(c) To minimize any unfavorable effects that marketing and international energy problems may have on the country.

(d) To reconcile environmental factors and the generation and use of energy, pursuant to the provisions of the Environmental Public Policy Act, as amended.

I HIBIT-3

(e) To minimize inequities or injustices which may arise as a result of economic or regional factors in terms of costs and availability of energy sources.

(f) To adopt a "Puerto Rico Energy Conservation Plan". This plan shall be established pursuant to applicable federal regulations.

(g) To promote, in coordination with the agencies mentioned in Section 9, scientific studies to provide Puerto Rico with alternate energy sources which may conform to its geographic and climatic conditions, which will contribute substantially to our economic growth by helping us to obtain a greater degree of self-sufficiency in energy matters. Special attention shall be given to solar energy and its associated sources, among others.

Section 2.—Development and Execution of the Energy Policy; Responsible Entity—

The Energy Office, created hereby, shall formulate and maintain a document which shall state in full the Energy Policy of Puerto Rico and the specific measures for its implementation. The document shall be worked out in harmony with the Planning Board's Integral Development Plan and the provisions of Act No. 75 of June 24, 1975.[52]

As part of the process of formulation, every entity or organization, as well as the general public, shall be given the opportunity to comment on the proposed document. For such purposes, copies thereof shall be printed and available for inspection and study, prior to the holding of public hearings. Any recommendation and observation received shall be considered at the time the document is drafted.

The document shall be submitted to the Governor's consideration not later than twelve (12) months from the date this act becomes effective. The Governor shall approve and enforce the same by Executive Order to that effect, or return it to the Office with his objections within thirty (30) days after the aforesaid document is submitted to him. After the Governor approves the document and issues the Executive Order enforcing the same, it shall have force of law and shall be binding and enforceable within every government program of the Executive Branch, as well as the government instrumentalities. The Energy Office shall be responsible for the coordination and supervision of the implementation of the public policy thus established.

[52] 23 L.P.R.A. §§ 62–63i.

The document thus adopted shall be brought up to date at least every four (4) years from its effective date onwards. Any proceedings to update this document shall require the holding of public hearings and shall be worked out in coordination with the Planning Board's Integral Development Plan.

Section 3.—Annual Reports on the Energy Situation.

The Governor shall submit a report on the energy situation to the Legislature in February of each year, which shall contain the energy situation in detail in Puerto Rico at that time, conclusions and recommendations of legislative and/or administrative actions leading to the solution of problems connected with said situation.

Section 4.—Advisory Committee on Energy; Creation, Constitution; Objectives; Meetings and Reports.—

(A) Creation and Constitution: The Advisory Committee on Energy is hereby created, which shall be composed of a Chairman appointed by the Governor, the Secretary of Natural Resources, the Executive Director of the Water Resources Authority, the Secretary of Consumer Affairs, the Director of the Energy and Environmental Research Center of the University of Puerto Rico, the Executive Director of the Environmental Quality Board, the Chairman of the Planning Board and four citizens designated by the Governor.

Two of the members shall be appointed by the Governor for a term of two (2) years and the other two members for a term of four (4) years. Successive appointments shall be made for four (4)-year terms.

Members of the Committee, who are not public officials, shall be entitled to receive per diems of fifty (50) dollars for each day in which they perform their work as members thereof.

(B) Objectives: The main objectives of the Committee shall be the following:

(1) To contribute to the development of a public policy on energy and to advise in the creative search for alternatives and solutions to the energy problem of Puerto Rico.

(2) To cooperate with industry, with public agencies and instrumentalities, and with the political subdivisions of the Government in the solution of technical problems which may affect our supplies of energy sources.

(C) Meetings and Reports: The Committee shall meet at the call of its Chairman, at least once (1) every ninety (90) days. It shall

servoir appurtenant to the Southern Coast Irrigation Service, m to pass from said dam to the Guayabal Reservoir, according of said irrigation service. If the estimated average water wenty-three million (23,000,000) gallons daily of this first stage, dition to the supply now regulated in the Guayabal Dam is be used upon construction of the Toa Vaca Dam and Reservoir, n Coast Irrigation Service shall retain for its own use the aters after deducting the amount of nine million (9,000,000) ater daily which is hereby allocated and made available to the id Sewer Authority for industrial and municipal (residential rcial) purposes in the southern-central region of Puerto 7, 1971, No. 11, p. 622, § 9.

HISTORY

s.

Rico Southern Coast Irrigation Service Act, cited in text, could be the Puerto igation Act of Sept. 18, 1908, p. 152, §§ 251-259 of this title.

Rico Public Irrigation Service, South Coast, as well as the Southern Coast rice, also cited, are specifically governed by Act Aug. 8, 1913, No. 128, p. 52, f not executed are set out as §§ 260-264 of this title.

Chapter 11. Puerto Rico Electric Power Authority

SECTION ANALYSIS

EXHIBIT-4

000505

Cross references.

Commonwealth Program for the Inspection and Regulation of Dams and Reservoirs. Executive Director as Committee Chariman, see § 404 of this title.

§ 195. Executive director

The Executive Director shall be appointed by the Board exclusively upon the basis of merit as determined by technical training, skill, experience, and other qualifications best suited to carrying out the purposes of the Authority. The Executive Director shall be removable by the Board but only for cause and after he has been given notice and an opportunity to be heard.—May 2, 1941, No. 83, p. 684, § 5; Apr. 8, 1942, No. 19, p. 330, § 1, eff. 90 days after Apr. 8, 1942.

HISTORY

Cross references.

Executive of Lajas Valley Irrigation District Committee. Executive Director member, see § 367 of this title.

§ 196. Powers of the Authority

The Authority is created for the purpose of conserving, developing, and utilizing, and aiding in the conservation, development, and utilization of water and energy resources of Puerto Rico, for the purpose of making available to the inhabitants of the Commonwealth, in the widest economic manner, the benefits thereof, and by this means to promote the general welfare and increase commerce and prosperity; and the Authority is granted and shall have and may exercise all rights and powers necessary or convenient for the carrying out of the aforesaid purposes, including (but without limiting the generality of the foregoing) the following:

(a) To have perpetual existence as a corporation;

(b) to adopt, alter, and use a corporate seal, which shall be judicially noticed;

(c) to prescribe, adopt, amend and repeal bylaws and regulations governing the manner in which its general business may be conducted and the powers and duties granted to, and imposed upon it by law may be exercised and performed; as well as, with the intention of guaranteeing the safety of the persons or the property, to regulate the use and enjoyment of its properties and of such other properties under its administration; the use and consumption of electric power; the intervention with and handling of equipment, enterprises, facilities, apparatus, instruments, wires, meters, transformers and objects of any analogous nature owned by the Electric Power Authority and which are used in connection with the production, transmission, distribution and use and consumption of the electric power produced by said Authority. The bylaws so adopted shall have force of law

once the provisions of §§ 1041-1059 of Title 3 are complied with. Any artificial or natural person who violates or induces to violate any provision of a bylaw promulgated in accordance herewith, shall be guilty of a misdemeanor and upon conviction thereof, shall be punished by a fine of not less than twenty-five (25) dollars nor more than one hundred (100) dollars or imprisonment in jail for a term of not less than one (1) month nor more than three (3) months or both penalties in the discretion of the court;

(d) to have complete control and supervision of any undertaking constructed or acquired by it including the power to determine the character of and necessity for all its expenditures and the manner in which they shall be incurred, allowed and paid without regard to the provisions of any laws governing the expenditure of public funds, and such determination shall be final and conclusive upon all officers of the Commonwealth Government, and to prescribe, adopt, amend, and repeal such rules and regulations as may be necessary or proper for the exercise and performance of its powers and duties or to govern the rendering of service or sale or exchange of water or electric energy;

(e) to sue and be sued, implead and be impleaded, complain and defend, in all courts;

(f) to make contracts and to execute all instruments necessary or convenient in the exercise of any of its powers;

(g) to prepare, or cause to be prepared, plans, designs, and estimates of costs for the construction, reconstruction, extension, improvement, enlargement, or repair of any undertaking or any part or parts thereof, and from time to time to modify such plans, designs, and estimates;

(h) to acquire in any lawful manner including, but without limitation, acquisition by purchase, whether by agreement or by the exercise of the power of eminent domain, lease, bequest, devise, gift, and to hold, maintain, use and operate any undertaking or parts thereof;

(i) to acquire in the manner set forth in subsection (h) hereof, produce, impound, develop, manufacture, treat, hold, conserve, use, transmit, distribute, supply, exchange, sell, rent and otherwise dispose of, water, electric energy, equipment, and such other things, supplies and services as the Authority shall deem necessary, proper, incidental, or convenient in connection with its activities; Provided, That in disposing at wholesale of electric energy the Authority shall give preference and priority as to supply to public bodies and cooperatives;

(j) to acquire in the manner set forth in subsection (h) hereof and to hold and use any property, real, personal, or mixed, tangible or intangible, or any interest therein, deemed by it to be necessary or convenient for carrying out the purposes of the Authority, and (subject to the limitations

000506

Chapter 75. Uniform Administrative Procedure

Subchapter I. General Provisions

SECTION ANALYSIS

Subchapter II. Procedure for Regulation

Subchapter III. Adjudicative Proceedings

Subchapter IV. Judicial Review

Subchapter V. Procedure for Granting Licenses, Franchises, Permits and Similar Actions

Subchapter VI. Supervision, Inspection and Joint Activities

Subchapter VII. Administrative Penalties

EXHIBIT-5

600507

Subchapter I. General Provisions

§ 2101. Public policy; construction

It is hereby established that the public policy of the Commonwealth is to encourage the informal solution of administrative issues so that formal solution of the matters submitted to the agency will be unnecessary. The agencies shall establish the rules and procedures that will allow the informal solution of the matters submitted for their consideration without impairing the rights guaranteed by this chapter. This section has the purpose of encouraging, without requiring or binding a party, to submit and resolve an issue through informal means.

The provisions of this chapter shall be construed liberally, thus guaranteeing that the administrative procedures shall be carried out in a speedy, fair and economical way that will ensure an equitable solution of the cases under the agency's consideration.—Aug. 12, 1988, No. 170, § 1.2, eff. 6 months after Aug. 12, 1988.

HISTORY

Statement of motives.

See Laws of Puerto Rico:

Aug. 12, 1988, No. 170.

Title.

Section 1.1 of Act Aug. 12, 1988, No. 170, provides: "This act [this chapter] shall be known as the 'Commonwealth of Puerto Rico Uniform Administrative Procedures Act'."

Repealing clause.

Section 8.3 of Act Aug. 12, 1988, No. 170, as amended by Act Nov. 30, 1990, No. 18, § 18, provides: "No. 112 of June 30, 1957 as amended [§§ 1041-1059 of this title] known as the '1958 Regulations Act' is hereby repealed."

"All regulations approved by agencies which have not been filed according to the provisions of this act [this chapter] or of former Act June 30, 1957, No. 112, and which are not contained in the compilations of regulations filed as of November 30, 1990, are hereby repealed."

"Furthermore, all regulations with limited effective periods which have already expired or which were approved under laws which have been repealed or have expired shall be considered repealed unless the appropriate agency extends the effective period by amending the regulation.

"Reorganization Plans, Executive Orders and Proclamations of the Governor are excepted from this repeal."

Applicability.

Section 8.4 of Act Aug. 12, 1988, No. 170, renumbered as § 8.5 by Act November 30, 1990, provides in pertinent part: "This act [this chapter]. . . shall be applied prospectively to pending administrative proceedings."

Special provisions.

Sections 8.1 and 8.2 of Act Aug. 12, 1988, No. 170, provide:

"Section 8.1.-Procedures not contemplated in this act. The agency shall regulate the practice of the administrative procedures not contemplated in this act [chapter], pursuant to the provisions of this act [chapter].

"Section 8.2.-Judicial statement of unconstitutionality. The judicial statement of unconstitutionality of any part of this act [this chapter] shall not affect the validity of its remaining provisions."

Section 8.4 of Act Aug. 12, 1988, No. 170, added Nov. 30, 1990, No. 18, § 19, provides: "Amounts received from payment of reasonable costs of reproduction, as authorized by subsection (d) of § 1.6 of this act [§ 2105 of this title], as financial sanctions referred to in § 3.21 of this act [§ 2170a of this title], shall constitute a special fund in each agency, receipts of which shall be deposited with the Treasury Department to cover, in part, the costs of reproduction of documents. Any unused amounts remaining as of June 30 of each fiscal year shall be transferred to the General Fund of the Commonwealth."

The following table correlates the provisions of the Regulations Act of 1958 with the Uniform Administrative Procedure Act of 1988 which constitutes this chapter.

Regulations Act of 1958 June 30, 1957 No. 112 Sections	3 L.P.R.A. Former Sections	Uniform Administrative Procedure Act Aug. 12, 1988 No. 170 Sections	3 L.P.R.A. Setions
1	1041	1.1	2101 nt
2	1042	1.3	2102
3	1043	—	—
4	1044	—	—
5	1045	—	—
6	1046	2.8	2128
7	1047	2.9	2129
8	1048	2.10	2130
9	1049	2.11	2131
10	1050	2.12	2132
11	1051	2.13	2133
12	1052	2.14	2134
13	1053	2.15	2135
14	1054	2.16	2136
15	1055	2.17	2137
16	1056	2.18	2138
17	1057	—	—
18	1058	2.19	2139
19	1059	—	—

ANNOTATIONS

1. **Generally.** Magriz Rodríguez y otro v. Empresas Nativas, Inc., Force Constructors, S.E., etc., CC-96-394 (05/12/97); Junta Dir. Cond. Montebello v. Fernández, 136 D.P.R. 223 (05/31/94); 1992 Op. Sec. Jus. No. 15.

2. **Administrative process.** 1992 Op. Sec. Jus. No. 17.

000508

The Uniform Administrative Procedure Act was enacted to bring the citizens fast, efficient and high quality public services, under the basic guarantees of the due process of law. Magriz Rodríguez v. Empresas Nativas, Inc., CC-96-394 (5/12/97).

§ 2102. Definitions

For the purposes of this chapter, the following terms or phrases shall have the meaning stated below:

(a) *Agency.*—Means any board, body, board of examiners, public corporation, commission, independent office, division, administration, bureau, department, authority, official, person, entity or any instrumentality of the Commonwealth of Puerto Rico or administrative body authorized by law to perform regulating, investigating or decision making functions, or with the power to issue licenses, certificates, permits, concessions, accreditation, privileges, franchises, or to accuse or adjudicate except:

(1) The Senate and the House of Representatives of the Legislature;

(2) The Judiciary Branch;

(3) The Governor's Own Office;

(4) The Puerto Rico National Guard;

(5) The Municipal Governments or their entities or corporations;

(6) The Commonwealth Election Commission;

(7) The Bureau of Conciliation and Arbitration of the Department of Labor and Human Resources;

(8) The Advisory Board of the Department of Consumer Affairs on the Classification System for Television Programming and Hazardous Toys.

(b) *Adjudication.*—Means the statement whereby an agency determines the rights, obligations or privileges that correspond to a party.

(c) *Record.*—Means all the documents which have not been exempted from disclosure by an act and other material related to a specific matter which is or has been under consideration by an agency.

(ch) *Head of an agency.*—Means any person or group of persons upon whom the final statutory authority of an agency has been conferred by law.

(d) *Official interpretation.*—Means the agency's official interpretation of any law or regulations administered by it, which is issued by petition of a party or by the agency's initiative and is made a part of the formal catalog of the agency's interpretations.

(e) *Intervenor.*—Means any person who is not an original party in any adjudicative process conducted by an agency and who has shown his qualifications or interest in the procedure.

(f) *Order or resolution.*—Means any specific decision or action applied by an agency which adjudicates certain rights or obligations of one or more persons, specifically, or that imposes administrative penalties or sanctions, excluding executive orders issued by the Governor.

(g) *Partial order or resolution.*—Means any action by an agency that adjudicates a right or obligation which does not terminate the total controversy but just a specific phase thereof.

(h) *Interlocutory order.*—Means any action by an agency in an adjudicatory procedure which resolves a purely procedural matter.

(i) *Person.*—Means any natural or juridical person of a public or private nature that is not an agency.

(j) *Party.*—Means any legally authorized person or agency towards whom the action of an agency is specifically addressed or a party to said action or who is allowed to intervene or participate therein or who has filed a petition for the review or compliance of an order or who is designated as a party in said procedure.

(k) *Administrative procedure.*—Means the drafting of rules and regulations, the formal adjudication of any controversy or question under the consideration of an agency, the granting of licenses and any investigative process initiated by an agency within the scope of its legal authority.

(l) *Rule or regulation.*—Means any rule or group of rules of an agency which is generally applied that executes or interprets public policy or the law or that regulates the requirements of the procedures or practices of an agency. The term includes the amendment, repeal, or suspension of an existing rule. Excluded from this definition are:

(1) Rules related to the internal administration of the agency that do not affect the rights or procedures or practices available to the general public directly and substantially.

(2) Forms and instructions, interpretations and statements of general policy that are merely explanatory and have no legal effects.

(3) Mandatory decrees approved by the Minimum Wage Board.

(4) Price decrees by the Department of Consumer Affairs and other similar decrees or orders that are issued or may be issued in the future by other agencies and which are merely a determination of one or several regulating parameters based on previously approved regulations which contain the issuing standards.

(m) *Regulation.*—Means the procedure used by an agency to draft, adopt, amend or repeal a rule or regulations.

(n) *Secretary.*—Means the Secretary of State.—Aug. 12, 1988, No. 170, § 1.3; Nov. 30, 1990, No. 18, § 1; Aug. 8, 1997, No. 60, § 5.

HISTORY

Amendments—1997.

Subsection (a): Act 1997 amended clause (8) generally.

—1990.

Subsection (a)(1): Act 1990 changed "Legislature" to "Senate and House of Representatives of the Legislative Assembly".

000509

Subsection (a)(8): Act 1990 added this subsection.
Subsection (n): Act 1990 added this subsection.

Statement of motives.
See Laws of Puerto Rico:
Aug. 8, 1997, No. 60.

ANNOTATIONS

1. Generally. Per §§ 2101 et seq. of this title, the Judicial Branch is not an administrative agency and as such dispositions relative to judicial revision of its decisions pertaining to administrative character do not apply. Rivera v. Dir. Adm. Trib., 144 D.P.R. — (1998); TSPR 98-10 (02/09/98). 1991 Op. Sec. Jus. No. 29.

2. Regulatory power. The administrative rules for the Corrective Action Plan only establish guidelines for the internal administration of the Comptroller's Office from recommendations made in its audit reports; therefore, it should be considered an exception to the definition of rules and regulations made by this section. Gobernador v. Hon. Cruz Manzano, Alcalde, AA-95-57 (03/10/97).

The law establishes as an exception to the requirements for the adoption of regulations, those of internal administration which do not affect the procedures and practices available to the general public. Gobernador v. Hon. Cruz Manzano, Alcalde, AA-95-57 (03/10/97).

An annulled regulation does not affect rights or procedures available to the general public simply because an agency has a public character. Gobernador v. Hon. Cruz Manzano, Alcalde, AA-95-57 (03/10/97).

§ 2103. Applicability

This chapter shall apply to all the administrative procedures conducted before all the agencies that are not expressly excepted by this chapter. The following functions and activities shall be excluded from this chapter:

Investigative and criminal procedure functions realized by the Department of Justice, the Special Investigations Bureau and the Puerto Rico Police.

Discretion is hereby granted to the agencies, in the measure that is necessary to prevent the denial of funds and services of the federal government of the United States of America which would otherwise be available, to adjust their administrative procedures to those required by applicable federal laws, and including the Administrative Procedure Act, 5 U.S.C. § 551 et seq. If the procedures of the Administrative Procedure Act are followed the agency shall not be obliged to duplicate procedures in the actions it may take and shall only use what is provided in said act in such matters that are pertinent to the action that is subject to an agreement, provision of funds or services, or a delegation of authority by the government of the United States. Even in such cases, the disclosure and publication requirements established by this chapter shall apply.—Aug. 12, 1988, No. 170, § 1.4; Nov. 30, 1990, No. 18, § 2, retroactive to 6 months after Aug. 12, 1988.

HISTORY

Text references.
The Administrative Procedure Act mentioned in the text is Act Sept. 6, 1966, P.L. 89-554, 80 Stat. 381, as amended.

Amendments—1990.
Act 1990 added the last sentence of the first paragraph, the second paragraph and the last sentence of the third paragraph.

§ 2104. Implementation

The Governor shall designate a Commission of five (5) members from among the Secretaries of his Cabinet, heads of agencies, members of boards or commissions, or other persons of recognized expertise in the field of administrative law to render a report to him and to the Legislature on the progress in the implementation of this chapter in the various agencies of the government of Puerto Rico, with its recommendations. This Commission shall be in charge of supervising and facilitating the implementation of this chapter. This Commission shall be operative for four (4) years counting from the effective date of this act, but its activities may be extended for additional terms at the Governor's discretion.—Aug. 12, 1988, No. 170, § 1.5; Nov. 30, 1990, No. 18, § 3, retroactive to 6 months after Aug. 12, 1988.

HISTORY

Text references.
Reference to "effective date of this act" is to Act Nov. 30, 1990, No. 18, which amended this section.

Amendments—1990.
Act 1990 added the second sentence.

§ 2105. Implementation—Terms and requirements

Within the term of one year from the date of approval of this act each agency shall:

(a) Prepare a diagram and summary describing its administrative and functional organization, the procedures for the approval of regulations, the manner of filing formal or informal petitions and the means by which the public can obtain information from the agency.

(b) Adjust its rules or regulations that establish the formal regulation and adjudicatory procedures, in accordance with the provisions of this chapter.

(c) Compile approved rules and regulations which were in effect as of February 8, 1989 and which were not previously filed at the State Department in accordance with Act No. 112 of June 30, 1957, as amended. Each agency shall submit the rules and regulations described in the

000510

·eceding sentence to the Office of the Secretary for publication in :cordance with § 2129 of this title, indicating as the effective date of each ıle or regulation the date as of which it originally became effective, ·oviding that each agency shall comply with the provisions of subsection) of this section within the period it provides.

(d) Have final orders, decisions and interpretations of laws adopted by ıe agency available for reproduction as requested by an interested party ·ter payment of reasonable reproduction charges. Each agency shall also ·epare and maintain a register of interpretations issued before June 30,)91, with thematic indices, which establish precedents or set standards. As ' July 1, 1991, said registers and indices shall include all interpretations ıd decisions.—Aug. 12, 1988, No. 170, § 1.6; Aug. 5, 1989, No. 43, § 1; Nov.), 1990, No. 18, § 4, retroactive to 6 months after Aug. 12, 1988.

HISTORY

ɛxt references.

Act No. 112 of June 30, 1957, referred to in subsection (c) was repealed by Act No. 170 of)88 which constitutes this chapter.

mendments—1990.

Subsection (d): Act 1990 amended this subsection generally.

-1989.

Subsection (c): Act 1989 amended this subsection generally.

Subchapter II. Procedure for Regulation

2121. Notice of proposed adoption of regulations

Whenever the agency proposes to adopt, amend or repeal a rule or egulation it shall publish a notice in a newspaper of general circulation in ᑭuerto Rico. The notice shall contain a summary or brief explanation of the ›urpose of the proposed action; a reference to the legal provision that ıuthorizes such action, and the form, place, days and hours that written :omments can be submitted or a written request, including the grounds on vhich the petitioner bases said request, for an oral hearing on the proposed ıction can be made, and where the complete text of the regulations to be ıdopted will be available to the public.—Aug. 12, 1988, No. 170, § 2.1; Nov. 30, 1990, No. 18, § 5, eff. Nov. 30. 1990.

HISTORY

Editor's notes.

This section was amended by Act Oct. 5, 1999, No. 310, but the official translation was not ıvailable at the time of publication. Please consult the Spanish version.

Amendments—1990.

Act 1990 added the phrase commencing "including the grounds ..." to the second sentence.

ANNOTATIONS

1. Generally. When a regulation, which is defined as a group of norms of general application that implements a public policy, is enacted, it has the same power as a law, since it determines the rights, duties or obligations of the persons subjected to the jurisdiction of the agency. Gobernador v. Hon. Cruz Manzano, Alcalde, AA-95-57 (03/10/97).

The Legislative Assembly has the authority to delegate the power of regulation to administrative bodies, as long as said delegation accompanies broad and general criteria that allow the development and execution of public policy, that is, that the approved regulations delimit and specify the agencies' powers in order to avoid illegal or arbitrary actions; and the court will evaluate whether: (1) the administrative action is authorized by law; (2) the power to regulate was properly delegated; (3) the regulation was approved in accordance with that delegated power; (4) the approval of the regulation complies with the procedural guidelines of the agency's organic act, and special laws; and, (5) the regulation is illegal or arbitrary. Gobernador v. Hon. Cruz Manzano, Alcalde, AA-95-57 (03/10/97).

The Comptroller's Office is empowered to establish regulations for the investigation and preparation of reports dealing with discovery of irregularities or violations of law and to follow up on investigated agencies and instrumentalities in order to avoid future violations. Gobernador v. Hon. Cruz Manzano, Alcalde, AA-95-57 (03/10/97).

An administrative agency adopts guidelines and interpretative rules to consolidate its internal procedures, establish limits of administrative discretion, or for internal purposes; said guidelines and rules are exempted from procedures of formal regulations, are intended to maintain the agency's flexibility, and do not therefore affect the rights of the parties. Gobernador v. Hon. Cruz Manzano, Alcalde, AA-95-57 (03/10/97).

It is a principle of administrative law that the reason for delegating regulatory authority is to facilitate implementation of the law, and the language of a statute shall not be interpreted to be modified or replaced by that of a regulation enacted to implement the statute. (Reiterating Op. Sec. Jus. Nos. 37 of 14 of 1956 and 29 of 1955.) 1988 Op. Sec. Jus. No. 25. 37 of 1959, 48 of 1958 (1973).

It is a rule of administrative law that regulations duly adopted or enacted by a government entity is compulsory as long as it is not modified or replaced by subsequent legislation or regulation. (Reiterating Op. Sec. Jus. Nos. 4 of 1980 and 9 of 1979.) 1986 Op. Sec. Jus. No. 23.

2. Informal regulations. From time to time administrative agencies may approve guidelines or interpretative rules which are adopted to provide procedural uniformity or for other internal purposes and which can be judicially modified. Agosto Serrano v. F.S.E., 132 D.P.R. 866 (3/8/93).

Where guidelines or interpretative rules are involved it is not necessary to comply with public notice and comment requirements established in §§ 2121 et seq. of this title. Agosto Serrano v. F.S.E., 132 D.P.R. 866 (3/8/93).

§ 2122. Public participation

The agency shall provide an opportunity to submit comments in writing during a term of not less than thirty (30) days counting from the date the notice was published.—Aug. 12, 1988, No. 170, § 2.2, eff. 6 months after Aug. 12, 1988.

§ 2123. Public hearings

The agencies may call for public hearings at their discretion or if their organic act or any other act makes it mandatory to do so.

000511

A taped or stenographic record of the hearing may be made. The presiding official shall prepare a report for the agency's consideration containing a summary of the oral comments that are made during the hearing.—Aug. 12, 1988, No. 170, § 2.3, eff. 6 months after Aug. 12, 1988.

§ 2124. Determination by agency

In addition to the written and oral comments submitted to it, the agency shall take into consideration its experience, technical competence, expertise, discretion and judgment.—Aug. 12, 1988, No. 170, § 2.4, eff. 6 months after Aug. 12, 1988.

HISTORY

Effectiveness.

See note under § 2101 of this title.

§ 2125. Rule or regulation—Contents, style, form

Any rule or regulation adopted or amended by an agency shall contain the following information in addition to the text:

(a) A reference to the legal provision that authorizes its adoption or amendment;

(b) a brief and concise explanation of its purposes or the reasons for its adoption or amendment;

(c) a reference to all the rules or regulations that are amended, repealed or suspended by its adoption;

(d) the date of its approval, and

(e) its effective date.—Aug. 12, 1988, No. 170, § 2.5, eff. 6 months after Aug. 12, 1988.

§ 2126. Rule or regulation—Record

The agency shall keep an official record available for public inspection, with all the information related to the proposed adoption of a rule or regulation, as well as the one that is adopted or amended, including, but without being limited to:

(a) Copies of every publication related to the rule or the procedure.

(b) Every petition, requirement, memorandum, or written comment filed with the agency, and any written material considered by the agency regarding the adoption of the rule and the procedure followed.

(c) Any report prepared by the official who presides at the hearing summarizing the contents of the presentations.

(d) A copy of any regulatory analysis prepared in the procedure for the adoption of the rule.

(e) A copy of the rule and an explanation thereof.

(f) All petitions for exceptions, amendments, repeal or suspension of the rule.—Aug. 12, 1988, No. 170, § 2.6, eff. 6 months after Aug. 12, 1988.

§ 2127. Rule or regulation—Nullity and time to file action

(a) A rule or regulation approved after the effective date of this act shall be null if it does not substantially meet the provisions of this chapter.

(b) Any action to dispute the validity of the face [sic] of a rule or regulation because of non-compliance with the provisions of this chapter shall be filed in the Circuit Court of Appeals within thirty (30) days following the effective date of said rule or regulation. Competence on the action [sic] shall correspond to the Circuit of the judicial region in which the domicile of the appellant is located.

(c) The action filed to dispute the procedure followed to adopt the rules or regulations in question shall not estop their effectiveness unless the chapter under which they are adopted expressly provides for the contrary.—Aug. 12, 1988, No. 170, § 2.7; Dec. 25, 1995, No. 247, § 1, eff. May 1, 1996.

HISTORY

Text references.

Reference to "the effective date of this act" is to Act Aug. 12, 1988, No. 170, which became effective 6 months after Aug. 12, 1988.

Amendments—1995.

Subsection (b): Act 1995 substituted "Superior Court of competent jurisdiction" with "Circuit Court of Appeals" and added the second sentence.

Statement of motives.

See Laws of Puerto Rico:

Dec. 25, 1995, No. 247.

Separability.

Section 9 of Act Dec. 25, 1995, No. 247, provides: "Should any section of this Act [which amended this section] be declared unconstitutional, in whole or in part, by a court with jurisdiction, such unconstitutionality shall not affect, impair or invalidate the remaining provisions of such section nor of this Act [which amended this section]."

ANNOTATIONS

1. **Generally.** Under this section, any person or party wanting to appeal the Planning Board's decision amending a zoning map has 30 days to request a judicial revision, beginning from the moment the amendment, the object of the revision, becomes effective; that is, the request must be made within the 45 days from when its publication took effect. Montoto v. Lori, 145 D.P.R. — (1998); TSPR 98-23 (03/11/98).

§ 2128. Rule or regulation—New regulations; filing

(a) All regulations approved by any agency of the Commonwealth of Puerto Rico shall be presented at the State Department in an original and

two (2) copies. As a general rule, regulations shall become effective thirty (30) days after the filing date unless:

(1) Otherwise authorized by the enabling legislation, in which case the date provided in the statute shall apply;

(2) the agency establishes an earlier effective date as part of the regulation if authorized by the enabling legislation, or

(3) the regulation is an emergency regulation as provided in § 2133 of this title.

(b) The agency may file, jointly or subsequently, an English translation of the regulation. In instances where the agency files an English translation, this shall not affect the effective date of the regulation.

(c) The requirement to file regulations in Spanish, as established in subsection (a) of this section, may be waived by the Secretary with respect to technical national standards which have been incorporated in a regulation as long as the agency files a request for waiver, in writing, stating the difficulties involved in obtaining a Spanish translation owing to the technical content of the regulations. If the Secretary determines that the request is reasonable he shall authorize the waiver in writing and a copy of the authorization shall be attached to the regulation. In such cases the standards shall be filed in English and shall be accompanied by the regulations and copies thereof in Spanish.

(d) The Secretary shall publish in two (2) newspapers of general circulation a summary of each filed regulation, including its number, effective date and the agency that approved it. The regulation shall be published within twenty-five (25) days after the date it was filed.

(e) In every case in which a citizen, an agency, including in addition to those listed in § 2102 of this title those of the Legislative and Judicial Branches, a partnership, a corporation or any other judicial person shall request, and adequately justify to the Secretary the necessity for, an English translation of any regulation or part of or amendment to a regulation, said official shall provide that the agency concerned shall prepare a translation and file it in the Office of the Secretary within the period he specifies, subject to the provisions of §§ 2129-2132 of this title.—Aug. 12, 1988, No. 170, § 2.8; Aug. 5, 1989, No. 43, § 2; Nov. 30, 1990, No. 18, § 6, retroactive to 6 months after Aug. 12, 1988.

HISTORY

Amendments—1990.

Act 1990 amended this section generally.

—1989.

Subsection (a): Act 1989 amended the first paragraph generally.

§ 2129. Rule or regulation—Publication requirements; form; statutory references

The Secretary shall prescribe, by regulations, the manner in which the regulations filed under § 2128 of this title are to be published. His regulations shall prescribe a conventional size to be used in filing the regulations pursuant to said section and shall provide that all regulations shall be accompanied by the reference to the legal authority under which said regulations or any part thereof are adopted, as well as the reference to the specific legal provisions it implements, complements or interprets, as the case may be, and a copy of the public notice referred to in § 2121 of this title. The regulations shall also require that all amendments to the regulations refer to the original regulations.

The Secretary may issue model regulations for the use of agencies as well as manuals and other instruments to facilitate the implementation of this chapter. In cases in which special laws require several agencies to issue regulations, the Secretary may file a model regulation following the procedures established in §§ 2121 et seq. of this title. Said model regulation shall apply to all agencies with the obligation to regulate except those agencies which have previously approved regulations for the subject of the model regulation.—Aug. 12, 1988, No. 170, § 2.9; Nov. 30, 1990, No. 18, § 7, retroactive to 6 months after Aug. 12, 1988.

HISTORY

Amendments—1990.

Act 1990 added "and a copy of the public notice referred to in § 2121 of this title" and added the second paragraph.

§ 2130. Evidence of filing; permanent register; public inspection

The Secretary shall record the date and hour that all copies of regulations are filed in his office, and shall keep a permanent file of said regulations in his office for public inspection.—Aug. 12, 1988, No. 170, § 2.10; Nov. 30, 1990, No. 18, § 8, retroactive to 6 months after Aug. 12, 1988.

HISTORY

Amendments—1990.

Act 1990 deleted a reference to English translations.

§ 2131. Approval of secretary of state

The Secretary shall examine all regulations filed in his office pursuant to § 2128 of this title in order to determine their compliance with the regulations approved by him pursuant to § 2129 of this title. If he approves it, he shall indicate his approval on each copy of the regulations and it shall

000513

ı be deemed that the regulations have been properly filed as required aw.—Aug. 12, 1988, No. 170, § 2.11, eff. 6 months after Aug. 12, 1988.

ı32. Correction of regulations

;, upon examination, the Secretary reaches the conclusion that a specific ılation does not comply with the provisions of this title or with the ulations approved by him pursuant to § 2129 of this title, the Secretary , then:

ı) Return it to the originating agency with a list of his objections so that ıay be corrected and drafted according to law, indicating to the agency ther the corrections constitute an amendment of the regulations for poses of §§ 2121 et seq. of this title.

ɔ) Make as many corrections or amendments as are needed for the ulations to merit the approval of the Secretary.

n either case, the regulations shall not be deemed as filed for the poses of this chapter until the originating agency has made the icated changes and the Secretary has approved the new text or said ncy has indicated its approval of the amendments made by the retary.—Aug. 12, 1988, No. 170, § 2.12; Nov. 30, 1990, No. 18, § 9, roactive to 6 months after Aug. 12, 1988.

HISTORY

endments—1990.

ct 1990, in the first paragraph, added "the provisions of this title or with".

ubsection (a): Act 1990 added the final clause beginning "indicating to the agency ...".

2133. Emergencies; waiver of publication requirement

The provisions of §§ 2121, 2122, 2123 and 2128 of this title may be waived all cases in which the Governor certifies that, owing to an emergency or y other exigent circumstance, the public interest requires that the gulation or amendment take effect without the delay required by 2121, 2122, 2123 and 2128 of this title. In all such cases the regulation or ıendment, together with a copy of the Governor's certification, shall be ed by the Secretary. Once the regulation or amendment is filed the ency shall comply with the provisions of §§ 2121, 2122, and 2123 of this le and, in the event of modification to or amendment of the regulation ed according to this section, shall file the same in the office of the cretary of State and shall comply with the provisions of § 2128 of this le.—Aug. 12, 1988. No. 170, § 2.13; Aug. 5, 1989, No. 43, § 2.

HISTORY

nendments—1989.

Act 1989 amended this section generally.

§ 2134. Published regulations; presumption; judicial notice

(a) The publication of a regulation in the "Commonwealth of Puerto Rico Regulations" raises a rebuttable presumption that the text of said regulations thus published is the text of the regulations adopted.

(b) The Courts of the Commonwealth shall take judicial notice of the contents of each of the regulations printed in the Commonwealth of Puerto Rico Regulations.

To such effects, the Secretary shall deliver a copy of the publication, free of charge, to the libraries of the Supreme Court, the Circuit Court of Appeals, the Court of First Instance and to the libraries of local universities' schools of law, as well as to the Library of the Federal District Court for the District of Puerto Rico.—Aug. 12, 1988, No. 170, § 2.14; Nov. 30, 1990, No. 18, § 10; Dec. 25, 1995, No. 247, § 2, eff. May 1, 1996.

HISTORY

Amendments—1995.

Subsection (b): Act 1995 amended the second paragraph of this subsection generally.

—1990.

Act 1990 deleted "Rules and" and "or the Commonwealth of Puerto Rico Register" from subsections (a) and (b) and added the last paragraph.

Statement of motives.

See Laws of Puerto Rico:

Dec. 25, 1995, No. 247.

Separability.

Section 9 of Act Dec. 25, 1995, No. 247, provides: "Should any section of this Act [which amended this section] be declared unconstitutional, in whole or in part, by a court with jurisdiction, such unconstitutionality shall not affect, impair or invalidate the remaining provisions of such section nor of this Act [which amended this section]."

§ 2135. Commonwealth regulations—Codification and publication

The Secretary is hereby authorized to:

(a) Contract for the compilation, codification, and publication of all the regulations filed in his office under § 2129 of this title. The publication of such compiled regulations shall be known as the "Commonwealth of Puerto Rico Regulations".

(b) Determine the manner and form that said compilation and codification shall be published, printed and indexed.—Aug. 12, 1988, No. 170, § 2.15; Aug. 5, 1989, No. 43, § 4.

HISTORY

Amendments—1989.

Subsection (a): Act 1990 deleted "in English and Spanish".

C00514

EXHIBIT-6

RESOLUCION Num. 1756

POR CUANTO: La Ley Federal PURPA (P.L. 95-617) de 1978 establece que las compañías de electricidad deben implantar programas de conservación de energía a través de la promoción de proyectos de cogeneración y de producción de electricidad en pequeña escala, asuntos que reglamenta la Comisión Federal Reguladora de Energía (FERC) mediante la Orden Núm. 69.

POR CUANTO: La reglamentación adoptada por FERC estipula que las compañías de electricidad establecerán tarifas para la compra de electricidad desarrolladas en base a costo evitado ("avoided cost"); adoptarán, mediante el proceso de vistas públicas, un plan para implantar procedimientos que respondan a la reglamentación del FERC; y proveerán información sobre costos a los proponentes de estos tipos de proyectos, entre otras cosas.

POR CUANTO: La Autoridad de Energía Eléctrica, en armonía con la política pública del Gobierno de Puerto Rico, también reconoce los méritos de estas alternativas de conservación de energía.

POR TANTO: La Junta de Gobierno de la Autoridad de Energía resuelve:

1. Implantar, con vigencia inmediata, las tarifas de cogeneración y aplicables también a pequeños productores de electricidad que se describen en el Exhibit I.

2. Adoptar con vigencia inmediata la reglamentación sobre estos asuntos que se describen en el Exhibit II.

3. Incluir la consideración de estas tarifas y el plan mencionados en la Agenda de las Vistas Públicas en que se tratarán los 6 estándares tarifarios de PURPA, que se celebrarán próximamente.

4. Designar como miembros del Panel Examinador de estos asuntos a los ciudadanos Milton Castro, Ingeniero Electricista y Raúl Torres Viera, Abogado.

Aprobada: 23 de abril de 1981

000515

EXHIBIT-7

APENDICE F

AUTORIDAD DE ENERGIA ELECTRICA DE PUERTO RICO

SAN JUAN, PUERTO RICO

Dirección Cablegráfica
FUEPA
Dirección Telex AC
315714

Apartado
Correo General
San Juan Puerto Rico

RESOLUCION NUMERO 1830

POR CUANTO, la Ley Federal PURPA (PL-95-617 de 1978) establece que las compañías de electricidad deben implantar programas para viabilizar proyectos de cogeneración y de producción de electricidad en pequeña escala con fuentes energéticas renovables; asuntos que reglamenta el "Federal Energy Regulatory Commission" (FERC) mediante la Orden Número 69; y

POR CUANTO, la reglamentación adoptada por FERC estipula que las compañías de electricidad, mediante el proceso de vistas públicas, establecerán tarifas para la compra de electricidad, adoptarán un plan para implantar procedimientos y condiciones de servicio que respondan a la reglamentación del FERC y proveerán información sobre costos a los proponentes de estos tipos de proyectos; y

POR CUANTO, la reglamentación adoptada por FERC dispone también que las compañías de electricidad deben tener disponibles tarifas de venta para suplir los siguientes servicios a cogeneradores y pequeños productores: Auxiliar, Suplementario, Interrumpible, y Mantenimiento; disposiciones con las que no contamos satisfactoriamente al presente en la tarifa de Potencia Eléctrica en Reserva (SBS); y

POR CUANTO, la Autoridad de Energía Eléctrica aprobó mediante la Resolución Número 1756 del 23 de abril de 1981, los términos y condiciones y tarifas de compra de energía para cogeneradores y pequeños productores de energía, en forma provisional, y la designación de un Panel Examinador para celebrar vistas públicas y considerar estos asuntos; y

POR CUANTO, el Panel Examinador, compuesto por el Lic. Raúl Torres Viera y el Ing. Milton Castro, celebró vistas públicas los días 29 y 30 de junio de 1981 en San Juan, Ponce, respectivamente, y ha sometido un informe con fecha del 26 de mayo de 1982, recomendando un documento de Tarifas y Condiciones de Servicio que recoge sustancialmente los cambios sugeridos en las vistas públicas, y también los cambios efectuados por la Autoridad a la tarifa SBS; y

600516

RESOLUCION NUMERO 1830

POR CUANTO, la Autoridad de Energía Eléctrica ha recomendado también algunos cambios al documento final de Tarifas y Condiciones de Servicio para clarificar algunas disposiciones; y

POR CUANTO, la Autoridad de Energía Eléctrica en armonía con la política pública del Gobierno de Puerto Rico también reconoce los méritos de estas alternativas de conservación de energía;

POR TANTO, LA JUNTA DE GOBIERNO DE LA AUTORIDAD DE ENERGIA ELECTRICA RESUELVE:

1. Poner en vigor efectivo el 21 de enero de 1983 los términos y condiciones de servicio y las tarifas de compra de energía que se incluyen en el documento "Tarifas y Condiciones de Servicio para Cogeneradores y Productores de Electricidad en Pequeña Escala", enumerado como Exhibit 1134.

2. Sustituir, efectivo el 21 de enero de 1983, la actual tarifa SBS por la nueva tarifa de "Potencia Eléctrica en Reserva a Voltaje de Transmisión o Distribución Secundaria" (Standby Service at Transmission or Primary Distribution Voltage) enumerado en el Exhibit 1135.

APROBADO: 21 de enero de 1983

G00517

EXHIBIT - 8

GOBIERNO DE PUERTO RICO

AUTORIDAD DE ENERGIA ELECTRICA DE PUERTO RICO

SAN JUAN, PUERTO RICO

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APARTADO 364267
CORREO GENERAL
SAN JUAN, PUERTO RICO 00936-4267

RESOLUCIÓN NUM. 2748

POR CUANTO: El Director Ejecutivo ha recomendado y solicitado a la Junta de Gobierno que considere la derogación del documento "Tarifas y Condiciones de Servicios para Cogeneradores y Productores de Electricidad en Pequeña Escala", y su versión en inglés, (aprobado mediante la Resolución Núm. 1830 del 21 de enero de 1983) y radicado en el Departamento de Estado, conforme a lo dispuesto en la Ley Núm. 170, del 12 de agosto de 1988, según enmendada, Ley de Procedimiento Administrativo Uniforme.

POR CUANTO: El mencionado documento tenía el propósito de establecer los requisitos generales y específicos para el establecimiento y operación de cogeneradores y pequeños productores de electricidad.

POR CUANTO: Al día de hoy, el documento no cumple con su propósito, toda vez que los requisitos allí establecidos no responden a la situación actual aplicable para los cogeneradores y pequeños productores de electricidad. Estos requisitos han perdido vigencia debido a las siguientes razones:

1. La Comisión Reguladora de Energía Federal (FERC, por sus siglas en inglés) ha promulgado reglas detalladas sobre el manejo de cogeneradores y pequeños productores de electricidad, las cuales la Autoridad utiliza actualmente para evaluar las propuestas presentadas por cogeneradores y pequeños productores de electricidad.

2. La mayoría de las propuestas de cogeneración que ha recibido la Autoridad son para facilidades con una capacidad mayor de 100 MW.

3. Los precios de compra de electricidad incluidos en estas tarifas ya no están disponibles.

POR CUANTO: La Junta de Gobierno endosa la recomendación de solicitar la derogación del referido documento conforme a la referida Ley Núm. 170, ante el Departamento de Estado.

POR TANTO: La Junta de Gobierno de la Autoridad de Energía Eléctrica, RESUELVE QUE:

El Director Ejecutivo queda autorizado para iniciar el procedimiento correspondiente para derogar el documento "Tarifas y Condiciones de Servicios para Cogeneradores y Productores de Electricidad en Pequeña Escala". Se continuará utilizando las reglas establecidas por "Federal Energy Regulatory Commission" (FERC por sus siglas en inglés) en aquellas áreas que sean aplicables.

APROBADA: 26 de enero de 1999

000519

EXHIBIT - 9

DATE: July 1, 2003

Por Yolanda Ramos
JUL 01 2003

TO: Ing. Yolanda Ramos - Planificación y Estudios
Autoridad de Energía Eléctrica, Santurce, Puerto Rico

FROM: Héctor Arana - Ave. E. Pol 497 - Suite 390
San Juan, Puerto Rico 00926
Tel. (787) 731-0610

SUBJECT: Instalación Molino de Viento - Residencia familia del señor Carmelo Félix Matta
Comunidad Especial Monte Carmelo, Monte Carmelo, Vieques, P.R.

Dear Ing. Ramos:

The purpose of this letter is to confirm my attendance to meet with you and your staff at ~~1:30~~ 9:00 AM YR PM on July 9, 2003 in the company of Ing. Ricardo Rodríguez del Valle, my electrical engineer.

As per attachment (s) to this letter you will find:

1.) Copy of electrical engineering plans, prepared by Ing. Ricardo Rodríguez del Valle, for the installation of a small wind turbine system, 1 kW Bergey Wind Turbine, Model BWC XL.1 VDC Battery Charging System, at the family residence of Mr. Carmelo Feliz Matta, located at Monte Carmelo, Vieques, P.R.

2.) Copy of the Owner's Manual for the 1 kW Bergey Wind Turbine System, Model BWC XL.1.

3.) Copy of the Owner's Manual for the 4 kVA Trace/Xantrex Model SW4024 DC/AC Inverter.

4.) Copy of the Xantrex Grid Tie Interface (GTI) Specification Manual.

5.) Copy of Puerto Rico Electric Power Authority ("PREPA") {September 13, 1984} Motion To Withdraw Intervention in Docket No. QF84-319-000 Vieques, filed before the Federal Energy Regulatory Commission.

6.) Copy of Puerto Rico Office of Energy Office ("PROE") {August 24, 1984} Motion to Intervene in Docket No. QF84-307-000 Culebra and Docket No. QF84-319-000 Vieques, filed before the Federal Energy Regulatory Commission, that stipulated: "As part of its efforts to attain energy independence, recently, PROE and the Department of Energy jointly adopted a Plan of Distribution of Refunds under the Commonwealth Oil Refining Company Consent Order." "Pursuant to the Plan, PROE will make available at least $1,645,000 for a loan program designed to encourage the deployment of small windmills, ..."

7.) Copy of Wind Energy Development Corporation (WEDCO) - Federal Energy Regulatory Commission ("FERC") Qualifying Facility ("QF") Status Certification, Docket No. QF84-319 Vieques and Culebra QF84-307 Small Power Production Facilities.

DIVISION DE PLANIFICACION
Y ESTUDIOS
DEPARTAMENTO DE SISTEMAS
DE GENERACION

8.) Copy (in part) of Puerto Rico Electric Power Authority ("PREPA") January 1983 Regulations - Rates and Conditions of Service for Cogenerators and Small Power Producers.

9.) Copy of Puerto Rico Electric Power Authority Governing Board Resolution Number 1830 for the Implementation of Public Law 95-617 "Public Utilities Regulatory Policies Act" ("PURPA") and Order Num. 69 of Federal Energy Regulatory Commission ("FERC") Regulations.

The purpose of making available the above documents and information to you and your staff, prior to our meeting on Wednesday, July 9,2003, is to provide ample time to the persons at PREPA to review the specifications of project and they be entirely familiar with its details.

Cordially,

Héctor Arana

Héctor Arana

JUL 01 2003

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CN 078-04479
REV. 11/05

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AUTORIDAD DE ENERGÍA ELÉCTRICA DE PUERTO RICO

EXHIBIT - 10

SAN JUAN, PUERTO RICO

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APARTADO 364267
CORREO GENERAL
SAN JUAN, PUERTO RICO 00936-4267

20 de abril de 2007

CERTIFICADA CON ACUSE DE RECIBO
7005 1820 0004 0525 8690

Sr. Héctor Arana
Ave. Emiliano Pol 497
Suite 390
San Juan, PR 00926

Estimado señor Arana:

RE: Proyecto Aerogenerador Monte Carmelo, Vieques

Recibimos su carta del 15 de marzo de 2007, en la que incluye el plano que radicó en la Región de Carolina. En la reunión del 6 de febrero de 2007 acordamos que dicho plano se entregaría en nuestra oficina para evaluar si cumplía con los requisitos que estableció la Autoridad. A pesar de que usted incumplió con dicho acuerdo y radicó el plano en la Región de Carolina, evaluamos el mismo. Encontramos que el plano cumple con lo que requirió la Autoridad, siempre y cuando la localización del desconectivo manual que se muestra del otro lado del pedestal del metro, se mantenga accesible al personal de la Autoridad.

Le incluimos dos borradores de contrato: uno de interconexión y otro para compra de energía. Queremos hacer constar que el contrato de interconexión está pendiente de la evaluación de la Oficina de Administración de Riesgos, por lo que más adelante le notificaremos los requisitos de seguros que se incluirán en el mismo. Le recordamos que para iniciar la negociación de dichos contratos es necesario que nos provea la siguiente información:

- Evidencia de que el señor Carmelo Félix Mata es propietario de la residencia en la cual se proyecta instalar el aerogenerador.

- Contrato con el señor Carmelo Félix Mata para permitir instalar el aerogenerador en su propiedad y que clarifique a quién se deben enviar los pagos.

Esperamos sus comentarios dentro de los próximos treinta días.

Atentamente,

Yoamarie Figueroa Aponte
Ayudante Ejecutiva del
Directorado de Planificación y Protección Ambiental

Anejos

c: Lic. Luis R. Torres
Copia Certificada con Acuse de Recibo
7005 1820 0004 0525 8706

Jul. 9. 2007 6:15PM No. 2356 P. 1/1

CN 078-04479
REV. 11/05

ESTADO LIBRE ASOCIADO DE PUERTO RICO
AUTORIDAD DE ENERGÍA ELÉCTRICA DE PUERTO RICO

EXHIBIT - 11

SAN JUAN, PUERTO RICO

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SAN JUAN, PUERTO RICO 00936-4267

9 de julio de 2007

Post-it® Fax Note 7671	Date	# of pages ▶
To Sr. Arana	From Sonia Miranda	
Co./Dept.	Co.	
Phone #	Phone #	
Fax # 787-287-9736	Fax # 289-4890	

Héctor Arana

Saludos Señor Arana:

Recibimos copia de su solicitud de información relacionada al proceso de evaluación de los estándares del EPAct 2005. A continuación nuestras respuestas:

El resultado de la investigación que realiza EPRI se recoge en un informe, sin embargo el mismo es bastante extenso por lo que sería necesaria una dirección de correo electrónico para enviárselo o si usted así lo interesa le enviaremos una copia por correo regular.

Las otras referencias utilizadas y la dirección de Internet donde puede conseguirlas son las siguientes:

Información de Proyección de Precio de Combustibles - La información sobre las proyecciones de precio de combustible a largo plazo utilizadas son las del Departamento de Energía Federal (DOE) y está disponible en la página de Internet de la *Energy Information Administration* (EIA). La misma se puede acceder en la siguiente dirección: http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html .

El IEEE Standard 1547 - Las obligaciones contractuales que tiene la Autoridad con la IEEE y las leyes de derecho de autor prohíben que la Autoridad distribuya copias del estándar IEEE 1547. El documento pueden obtenerlo directamente de la IEEE través del la página: http://ieee.org/web/publications/home/index.html sin embargo, los estándares IEEE no son libre de costo.

NARUC Model Interconnection Procedures and Agreement for Small Distributed Generation Resources - El informe de *NARUC* está disponible en la Internet accediendo a la siguiente página:
http://files.harc.edu/Sites/GulfCoastCHP/Publications/ModelInterconnectionProcedures.pdf

Esperamos que la información brindada cubra sus inquietudes.

Atentamente;

Sonia Miranda Vega

C 00524

EXHIBIT-3

PUERTO RICO ELECTRIC POWER AUTHORITY

RATES AND CONDITIONS OF SERVICE FOR COGENERATORS AND SMALL ELECTRIC POWER PRODUCERS

Planning and Research Division

January, 1983

TABLE OF CONTENTS

000526

B

TERMS AND CONDITIONS FOR COGENERATION AND SMALL POWER PRODUCER PROJECTS:

(Official Spanish version adopted January 21, 1983)

I. INTRODUCTION

In 1978, the U.S. Congress approved Public Law PL95-617, titled "Public Utilities Regulatory Policies Act of 1978". One of the purposes of this legislation is to stimulate energy conservation by utilizing cogeneration and the small-scale production of electric energy. "Cogeneration" occurs whenever non-renewable fossil fuels are used for the simultaneous production of process steam and electric energy. On the other hand, "small-scale energy production" can be derived from the use of renewable resources for the generation of electric power.

The faculty of implementing the law is vested on the Federal Energy Regulatory Commission (hereinafter named "FERC"). In order to comply with its endeavor, the Commission has adopted certain regulations. Specifically FERC Order no. 69 requires that all electric utilities, whichever their size, comply with certain activities to enable the promotion of cogeneration and small-scale power production. Hereinafter, both cogenerators and small power producing facilities shall be referred to as "qualified facility" or "QF".

The Puerto Rico Electric Power Authority, being an electric utility, has developed its own plan to comply with Order 69, as issued by the FERC. Therefore, all entities which desire and are able to enter into a contract with PREPA for those purposes, may do so. If these entities achieve the status of qualified facility, are elegible to request service under the rules established by both FERC and PREPA for the purchase of power from such facility.

000527

II. DEFINITIONS

The terms defined by FERC Order no. 69 (18 CFR Part 292) shall have the same meaning for this regulation, except as otherwise re-defined.

2.1 Reliable Capacity: The figure for capacity given to generation equipment which meets the Authority criteria for classifying such equipment. This criteria includes (but is not limited to) availability, reliability, type of equipment, and the degree of coordination possible between the qualified facility and the Authority.

2.2 Capacity Credit: The periodic payment that PREPA will make to the "QF", in dollars per KW, as credit for the capacity that the customer will make available for the use by the Authority.

2.3 Energy Credit: The periodic payment that PREPA will make to the "QF", for each KWH that such customer sells to the Authority for the applicable billing period.

2.4 Aggregate Capacity: The sum of the individual reliable capacities of one or more generators connected to the "QF" 's electric system.

2.5 Energy: Electric energy measured in kilowatt-hours at the point of metering.

2.6 Point of Metering: The point or points where electric energy and/or demands are measured.

2.7 Interconnection Point: The point or points where the qualified facility will either recieve or deliver electric energy or both demand and energy under normal operating conditions.

2.8 Authority Norms: Any of the practices, methods, and related actions approved by a significant portion of the electric industry concerning reliability, security, and expediting, and adopted by PREPA.

000528

A P P E N D I X - B

Metering Schemes For The Various Rates

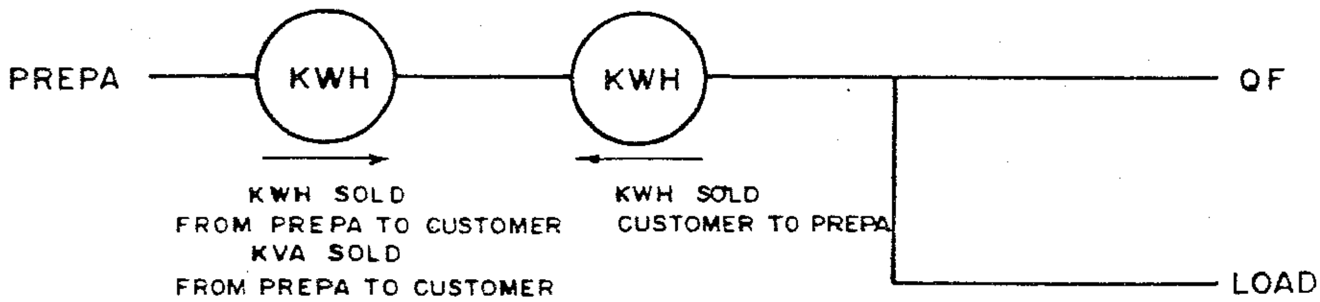
N O T E :

Examples 1-A, 2-A, and 3-A illustrate the required metering for cases in which the customer sells only excess energy over its own needs. Examples 1-B, 2-B, and 3-B illustrate the metering for the simultaneous purchase and sale option (Customer sells the entire output from the generator and buys all his load at the applicable PREPA rates. Examples numbered 1, 2 and 3 represent rates GPE-1, GPE-2, and GPE-3, respectively.

000529

TYPICAL METERING SCHEMES FOR THE VARIOUS RATES

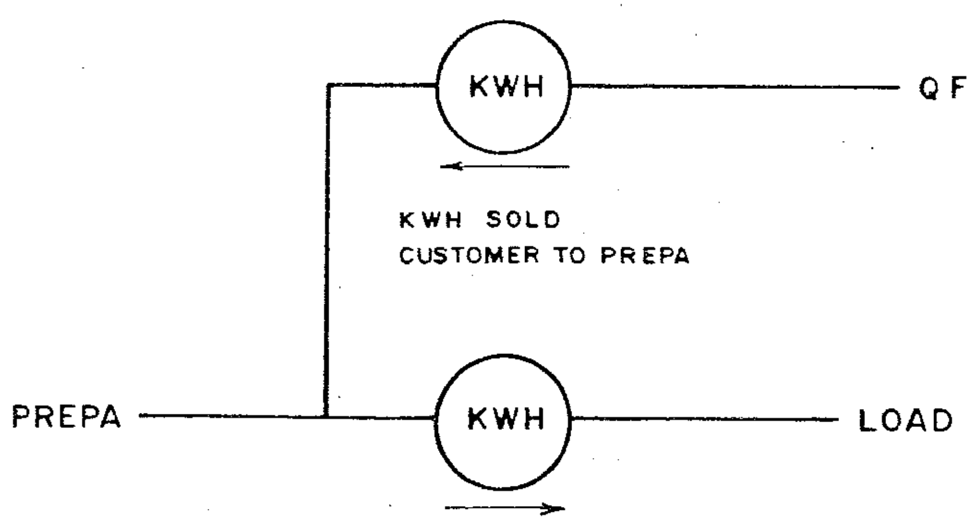
EXAMPLE I-A



RATE GPE-I

(DIRECT OR INDIRECT METERING. LOAD AND GENERATOR DIRECTLY INTERCONNECTED. METERS MUST HAVE DETENTS TO PREVENT BACKWARD MOVEMENT.)

EXAMPLE I-B

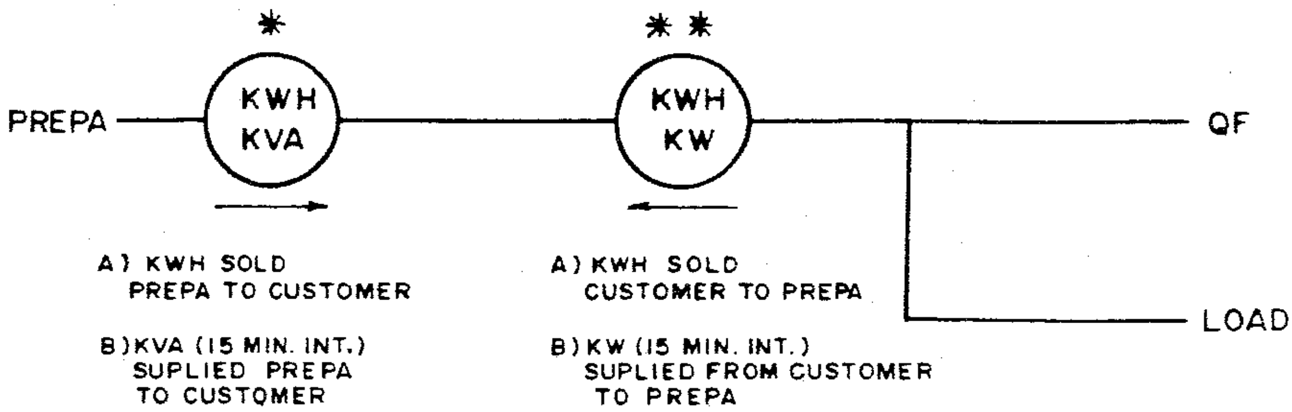


RATE GPE-I

(DIRECT OR INDIRECT METERING. LOAD AND GENERATOR CONNECTED TO SINGLE SERVICE DROP.)

000530

EXAMPLE 2-A



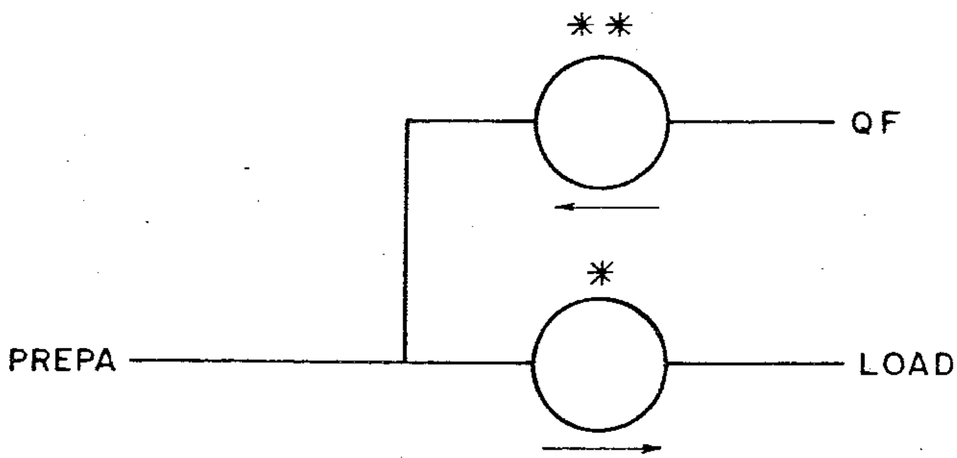
* KVA THERMAL INDICATOR COMBINED WITH KWH (WITH DETENT)

** KW INDICATOR COMBINED WITH KWH (WITH DETENT)

RATE GPE – 2

(LOAD AND GENERATOR DIRECTLY INTERCONNECTED)

EXAMPLE 2-B



RATE GPE – 2

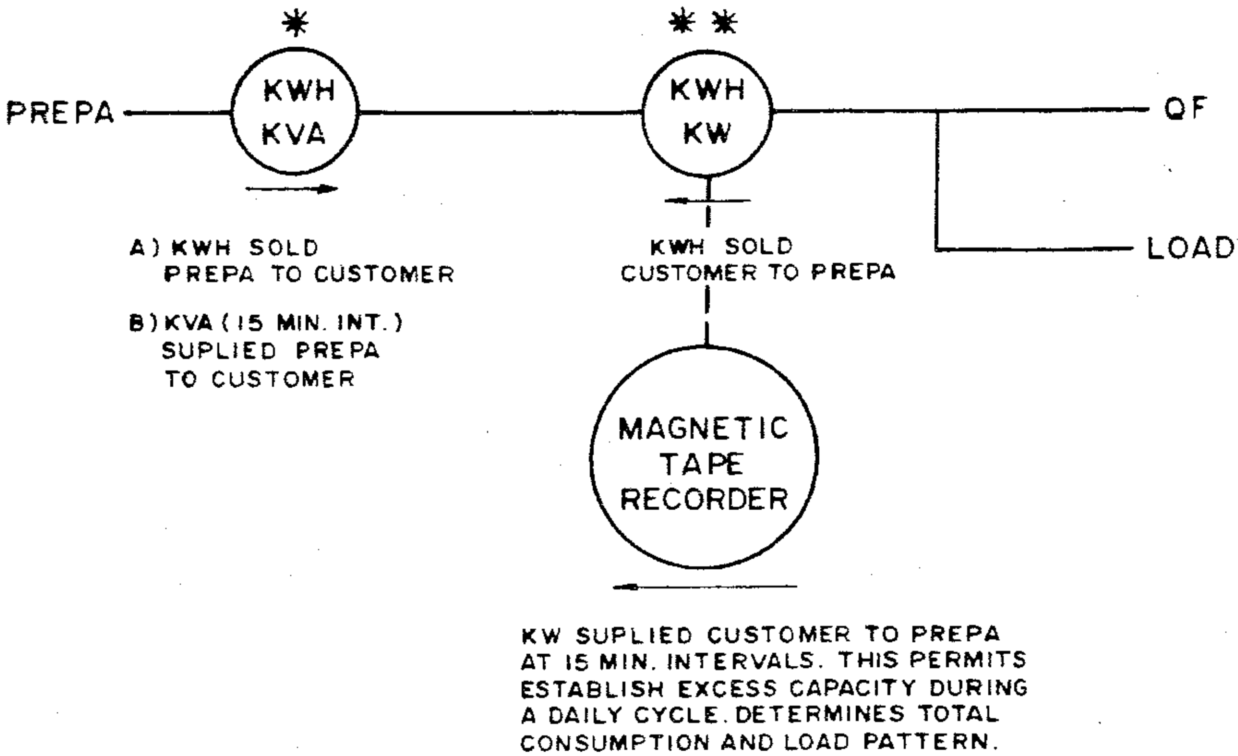
(LOAD AND GENERATOR CONNECTED TO SINGLE SERVICE DROP)

* SIMILAR TO 2-A, WITHOUT DETENT

** SIMILAR TO 2-A, WITHOUT DETENT

C0C531

EXAMPLE 3-A

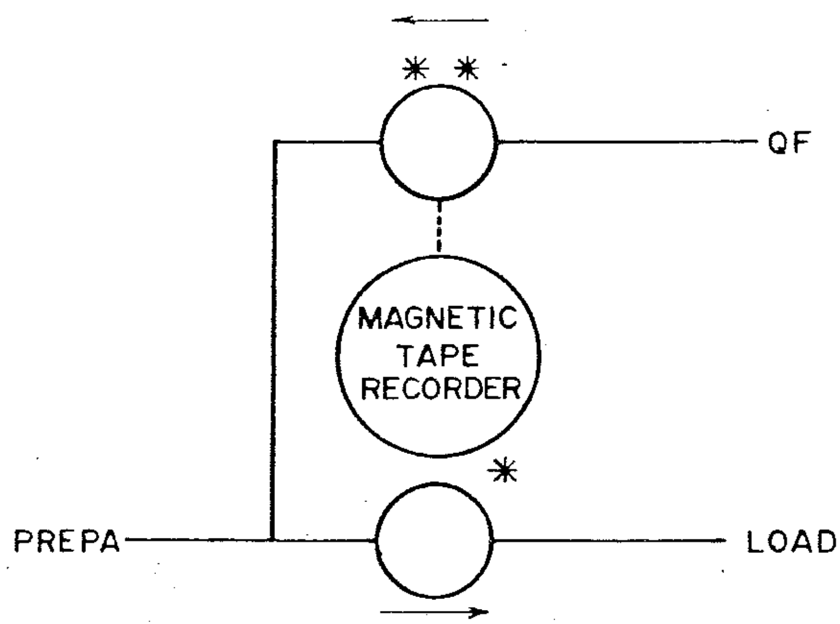


* KVA THERMAL INDICATOR COMBINED WITH KWH (WITH DETENT MAY BE SUBSTITUTED BY RECORDING EQUIPMENT (KW AND KVA) OR MAGNETIC RECORDER (KW AND KVA)

** KW INDICATOR COMBINED WITH KWH. HAS DETENT AND PULSE GENERATOR.

RATE GPE - 3

EXAMPLE 3 - B



* SIMILAR TO 3-A, WITHOUT DETENT

** SIMILAR TO 3-A, WITHOUT DETENT

RATE GPE-3

000532

APPENDIX - C

Rate Schedules for Purchase of Energy - F. Y. 1982-83

GENERAL RATE FOR PURCHASE OF ENERGY FROM CUSTOMER-OWNED GENERATION EQUIPMENT

Designation: GPE-1

Available: In the Commonwealth of Puerto Rico, to qualifying cogeneration or small power producing facilities, as designated by Section 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA).

Applicable: To residential or general service customers at any service voltage which receive concurrently electric service under any of the various rate schedules and operate generating equipment in parallel with the Authority system, upon previous consent of the Authority.

Character of Service : Alternating current, 60 hertz, three or four wire on secondary, primary, or transmission voltage at the Authority's option. Generators rated at 10 KVA or less may be single phase. Any generator with a name-plate rating of more than 10 KVA must be three phase. Any additional equipment, required in excess of such apparatus already necessary for providing regular service from Authority to customer, must be provided by the customer. The total costs of any revamping of existing lines, which may be necessary to accept the customer generation, will be absorbed by the customer.

Special Conditions:

1. In addition to the regular terms and conditions for electric service, certain rules and conditions for parallel operation will apply to the qualified facility as determined by the Authority and specified in the contract for this particular service.

2. The energy delivered from customer to Authority shall be metered separately from the energy delivered from Authority to customer under the various rate schedules. All energy purchased shall be measured either at the same specified point of delivery for the sale of electricity, or at any other point at the customer premises. Purchased energy shall be compensated for losses, if measured at a different point from the specified interconnection point.

Special Conditions (Cont'd.)

3. Electric power produced by customer shall not be transferred by such customer to another person or entity, with exception of subsidiary companies to the facility located at the same land premises.

4. The additional metering equipment for the purchase of energy shall be solely controlled by the Authority.

5. Under this rate schedule, no capacity credit will be paid to the customer.

Rate for Purchase of Power supplied by Customer to the Authority:

Monthly Energy Credit

5.2 cents for each KWH supplied by the Customer to the Authority, as measured at the point of delivery. This rate will apply for the 12 month period from July 1, 1982 to June 30, 1983. The price for the purchase of excess energy will be revised at the end of each fiscal year. Such revised price will then apply to the next 12 month period.

At the end of each fiscal year, the Authority will revise and adjust retroactively the credit paid for energy, in accordance with the Cogeneration Adjustment Clause in force.

Term of Contract: One year minimum. Renewable yearly, thereafter.

Effective Date: January 21, 1983

C00535

GENERAL RATE FOR PURCHASE OF ENERGY AND CAPACITY FROM CUSTOMER-OWNED GENERATING EQUIPMENT

Designation: GPE-2

Available: In the Commonwealth of Puerto Rico, to qualifying cogeneration or small power producing facilities, as designated by Section 210 of the Public Utilities Regulatory Policies Act of 1978 (PURPA). This rate will be available when the Authority determines that the addition of this capacity is necessary to improve the reliability of the system during the contractual period.

Applicable: To residential or general service customers at any service voltage which receive concurrently electric service under any of the various rate schedules and operate generating equipment in parallel with the Authority system, upon previous consent of the Authority.

Character of Service:

Alternating current, 60 hertz, three or four wire on secondary, primary, or transmission voltage at the Authority's option. All generators over 10 KVA shall be three phase. The total costs of any revamping of existing lines, which may be necessary to accept the customer generation, will be absorbed by the customer.

Special Conditions:

1. In addition to the regular terms and conditions of electric service, certain special rules and conditions for qualifying a facility for parallel operation and interchange of energy will apply, as determined by the Authority and specified in the contract for this particular service.

2. The energy and capacity delivered from customer to the Authority shall be metered separately from the energy and capacity delivered from Authority to customer under the various rate schedules. All energy and capacity purchased from the customer shall be measured either at the same specified point of delivery for the sale of electricity, or at any other point at the customer premises. Energy and demand purchases shall be compensated for losses, if measured at a different point from the specified interconnection point.

G00536

Special Conditions (Cont'd)

3. Electric power produced by customer shall not be transferred by such customer to another person or entity, with exception of subsidiary companies to the facility, located at the same land premises.

4. The additional metering equipment for the purchase of energy and capacity shall be controlled solely by the Authority.

5. The customer shall establish the contracted "excess capacity" for sale to the Authority. The capacity credit to be paid to customer shall be based on the higher of: the contracted excess capacity, or the actual delivered excess capacity during a 15 minutes period in the billing period. However, no additional capacity credit will be paid for any excess capacity which exceeds 110% of the contracted capacity.

6. The term "excess capacity factor" shall be defined as the ratio of: the total KWH delivered by customer to Authority during the billing period divided by the KWH computed as the product of: the contracted excess capacity in KW or the established excess KW capacity during the billing period, (the higher of both) multiplied by the total number of hours in the billing period.

7. The term "excess capacity" shall be defined as the excess generating capacity in KW over the customer's total electric load in KW at the same site.

000537

Rate for Purchase of Power Supplied by Customer to the Authority:

Monthly Energy Credit

5.2 cents for each KWH supplied by the customer to the Authority, as measured at the point of delivery. This rate will apply for the 12 month period from July 1, 1982 to June 30, 1983. The price for the purchase of excess energy will be revised at the end of each fiscal year. Such revised price will then apply to the next 12-month period.

At the end of each fiscal year, the Authority will revise and adjust retroactively the credit paid for energy, in accordance with the Cogeneration Adjustment Clause in force.

Monthly Capacity Credit

$0.40 per each KW of contracted excess capacity or $0.40 per each KW of maximum excess capacity actually delivered during a 15 minutes period, whichever is higher of both; except that no capacity credit will be computed for any excess over 110% of the contracted excess capacity.

Penalty for Availability of Capacity Below Standards

The following penalty will be deducted from the above monthly capacity credit:

$0.001 for each KWH not delivered to maintain at least a 70% excess capacity factor. These KWH shall be computed as follows:

KWH penalty = (No. of hours in billing period) X (KW used to compute the capacity credit above) X (0.70) - (actual KWH delivered)

If the KWH actually delivered to Authority are greater than the KWH computed at a 70% "excess capacity factor", the penalty will not be applied to the monthly bill.

Term of Contract: Two years minimum. Renewable every 2-years thereafter.

Effective Date: January 21, 1983

000549

ASOCIACIÓN DE INDUSTRIALES DE PUERTO RICO
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Edgardo Fábregas
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William Riefkohl
Vicepresidente Ejecutivo

10 de julio de 2007

Autoridad de Energía Eléctrica

Roberto J. Monserrate Maldonado 10/07/07
Vicepresidente de Asuntos Legales y Legislativos

Estándares EPACT05: "Smart Metering" (#1252) y "Interconnection" (#1254)

Queremos por este medio expresar nuestra posición en torno a la adopción de los estándares de "Time-Based Metering" y "Interconection Standards" por la Autoridad de Energía Eléctrica, los cuales están siendo discutidos en vistas públicas los días 9 y 10 de julio de 2007.

La AEE esta llevando a vistas públicas la determinación de "adoptar o no" dos (2) de los cuatro estándares contemplados en EPACT05: "Timed-Based Metering" y "Interconnection Standards". Esperamos que los otros dos estándares puedan ser igualmente considerados y adoptados en un futuro cercano, ya que resultarían ser de gran interés para los usuarios.

La Asociación de Industriales recomienda que se adopten TODOS los estándares contenidos en el "Energy Policy Act" 2005 (EPACT05), en su "TITLE XII-ELECTRICITY, Subtitle E-Amendments to PURPA)" que enmienda la "Public Utility Regulatory Policies Act of 1978 (PURPA)" en 4 áreas o estándares, a saber:

1) "Net metering"
2) "Smart metering"
3) "Cogeneration and small power production purchase and sale requirements"
4) "Interconnection"

La Autoridad de Energía Eléctrica (AEE) debe aprobar e implementar estos estándares que promueven la conservación de energía, aumentan la eficiencia de las instalaciones eléctricas y los recursos, y crean tarifas más justas para los consumidores de electricidad en Puerto Rico. Todo esto fortalece la economía de Puerto Rico y mejora su competitividad para seguir fomentando la inversión local y extranjera.

La adopción del estándar de "Smart Metering" por la AEE es una verdadera necesidad para todos los usuarios de energía eléctrica hoy en día en Puerto Rico, sean grandes industrias, comerciantes, o consumidores individuales. Se debe

G00540

fomentar en la AEE la creación de una diversidad de tarifas según la hora del día y la producción de energía para incentivar el uso y el ahorro de la misma. Si la AEE flexibiliza el acceso a varios tipos de tarifas, una mayor cantidad de usuarios se beneficiarían al poder escoger parte de su uso de energía de acuerdo con el costo. El ahorro en energía beneficiaría tanto a los usuarios como a la propia AEE que tendría mas capacidad para redistribuir recursos en casos de emergencia en el suministro de energía. Actualmente, la AEE sólo provee una tarifa basada en tiempo de uso (denominada "TOU") y ésta es exclusivamente para clientes en la industria y el comercio, quienes tienen un consumo masivo de energía.

La adopción del estándar de "Interconnection" por la AEE es otra necesidad muy importante para los usuarios en Puerto Rico. Mediante la interconectividad la AEE podría fomentar el uso de energía alternativa, disminuyendo la necesidad de producción en algunos casos para la AEE.

Por las razones mencionadas, la Asociación de Industriales recomienda que se adopten los estándares contenidos en la "Energy Policy Act 2005 (EPACT05)". Como ya hemos mencionado, los beneficios y ahorros para todas las partes, incluyendo a la industria, los individuos, la propia AEE y todo Puerto Rico son sumamente significativos.

000541

From: "Agnes Ortiz" <agnes@prma.com>
To: <epact05@prepa.com>
Date: 7/10/2007 1:59 PM
Subject: Ponencia Asociación de Industriales - AEE
Attachments: Ponencia AIPR - AEE - 10 jul 2007.PDF

Participate in CompRoad - our new Compensation Study conducted by Innova (Edwin Álvarez, 787-282-0510)

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Next events:
October 27, 2007 - Annual Scholarship Fund Golf Tournament, Palmas Del Mar Country Club
November 7-8, 2007 - Executive Summit, El San Juan Hotel & Casino

000512