The Energy Policy Act of 2005 and its Impact on Distributed Generation

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Abstract: *The Energy Policy Act of 2005 substantially modifies a number of past energy legislation and adds new legislation. This will impact the applications, R & D efforts and perhaps how electricity will be delivered and utilized in the foreseeable future. A part of the bill has the stated purpose of achieving energy self-sufficiency by the year 2025 (a very ambitious goal) within the United States, Canada, and Mexico. This bill also has provisions for anyone wishing to connect to the existing power grid (either at the transmission or distribution level) and sell power to a utility or other entity including incentives for generation of electricity from certain types of sources. This paper will provide a comprehensive review and describe the impact of this bill on distributed generation, the electricity market, the national electrical grid, and the future of how electricity will be delivered in the U.S.*

I. INTRODUCTION

"To ensure jobs for our future with secure, affordable, and reliable energy," [1] thus begins the Energy Policy Act of 2005 which includes measures ranging from the modification of daylight savings time to the initiation of a program to produce hydrogen from both new and existing nuclear facilities. The section of the bill titled "Set America Free Act of 2005" has the further stated purpose of "making recommendations for a coordinated and comprehensive North American energy policy that will achieve energy self-sufficiency by 2025 within the contiguous North American nations of Canada, Mexico, and the United States."[1]

The press release issued by the White House when the bill was signed stated that "The President's national energy plan will encourage energy efficiency and conservation, promote alternative and renewable energy sources, reduce our dependence on foreign sources of energy, increase domestic production, modernize the electricity grid, and encourage the expansion of nuclear energy." Part of the plan set out in this bill directly impacts generation connected at the distribution level.

In 2003 there were a total of 15,756 generators in the United States with a combined nameplate capacities of 1.031 x 10^6 MW [2]. A breakdown of how these generators are fueled is shown in Figure 1.

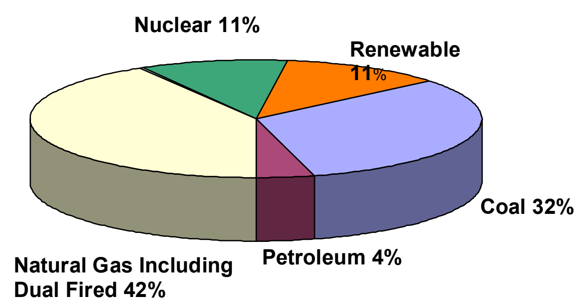

Fig. 1: Installed Generation Capacity (% MW) by Fuel

11% of the total installed capacity using renewable sources (including hydro) can be further broken down by fuel type, as depicted in Figure 2.

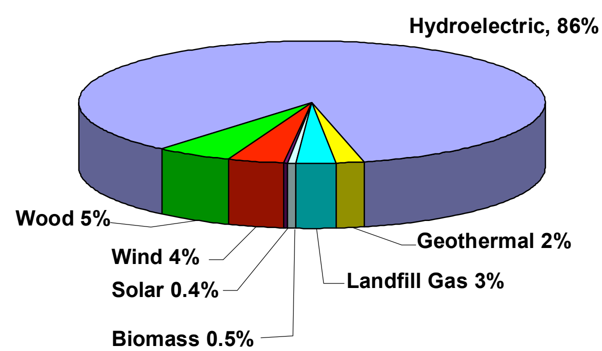

Fig. 2: Installed Renewable Generation Capacity (% Renewable MW) by Fuel

In 2003 all the electrical generation in the Unites States produced a combined total energy of 3.88 x 10^{12} kWh. This again could be broken down by fuel type and is shown in Figure 3 [3].

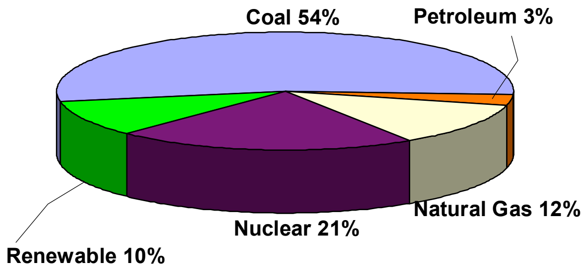

Fig. 3: Energy Production (% kWh) by Fuel Type

10% of the energy generated by renewable sources (including hydro) can be further broken down by fuel type as shown in Figure 4.

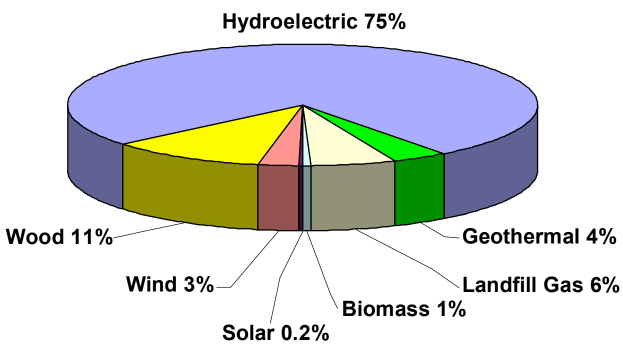

Fig. 4: Energy Production (% Renewable kWh) of Renewable Sources

It is interesting to note that while nuclear installed (MW) capacity is only 11% of total generation capacity it produced 21% of the nation's energy and coal is only 32% of the installed capacity but produced 54% of the nation's energy. Coal and nuclear sources alone made up 75% of the total energy consumed in the U.S. All renewable sources made up 11% of the nations installed generation capacity but generated only 10% of the energy used. Furthermore, 75% of all renewable energy is still produced by hydroelectric power plants.

The generation capacity and corresponding energy production requires an understanding of the concept of "*capacity factor*." The annual capacity factor can be defined as the actual energy produced by a power plant in a given year divided by the maximum energy it could produce if its generators operated 24 hours a day for 365 days a year (100% of the time).

Capacity factors can vary from one fuel to another for several reasons. Nuclear and coal plants, as an example, are used for base loading since they cannot be turned on and off quickly. These units are also much larger in size (400-1,200 MVA range). These types of plants would typically have higher capacity factors since they have relatively low-cost fuel, available nearly 100% of the time and are running as much as possible. Figure 5 shows the combined annual capacity factors for all generators in the United States by fuel type [3]. Nuclear plants have the highest capacity factor of 83% followed closely by wood, geothermal, and coal.

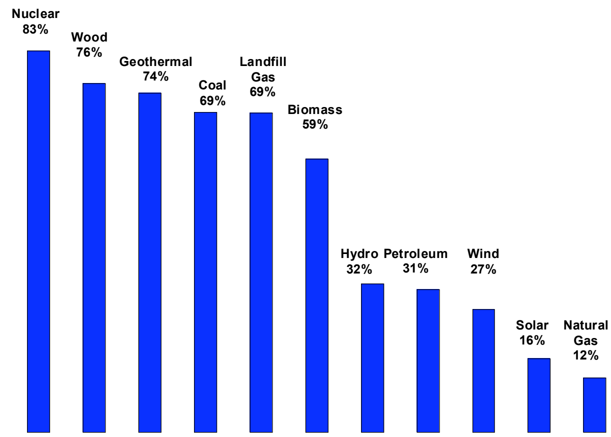

Figure 5: Annual Capacity Factors by Fuel

The relatively more expensive fuels are used only in plants utilized for peaking units. Natural gas and petroleum fall into this category. These types of plants deliver energy when needed for shorter periods of time or under emergency conditions and can be started quickly (within minutes). However the fuel is more expensive compared to coal or nuclear power plants. These plants are, in general, relatively smaller (5-200 MW range) in size. They run only when peaking power is required and the high cost of fuel can be justified. That is why natural gas and petroleum plants have relatively low capacity factors.

Other types of power plants have their capacity factors limited by the availability of fuel. Hydroelectric, photovoltaic (PV), and wind plants fall into this category. Hydroelectric plants, for example, can produce power any time of the day or night as long as fuel (potential and kinetic energy) in the form of water behind a dam (or other head) is available. Solar (PV) plants are limited to the daylight hours, and wind plants, especially those located inland, often have unpredictable fuel (wind velocity) supplies. This reduces their capacity factors and it is understandable why solar and wind plants have the lowest capacity factors among the renewable sources.

Capacity factors are important when deciding how much generation capacity must be installed to produce a certain amount of energy in a year. For example, if we needed to produce 1,000 kWh/day of energy for one year we could do this from 50.2 kW of nuclear generation with a capacity factor of 83% (50.2 x 24 x 0.83 = 1,000). If we wanted to do this with solar which has a capacity factor of 16% (and we could store the excess energy for use at any time) we would have to install 260.4 kW of generation (260.4 x 24 x 0.16 = 1,000). So the capacity factor determines how much of a particular technology needs to be installed to cover electrical energy usage.

The Energy Policy Act of 2005 directly authorizes $800 million for various types of distributed generation projects and research. The appendix breaks down the use of these funds. This paper will provide a comprehensive review of the bill's potential impact on distributed resources (DR) and explore how electricity will be delivered in the U.S into the future.

II. GRANTS TO SMALL COMMUNITIES

The energy bill provides for certain grants to small rural communities defined as a city, town, or unincorporated area with a population of less than 10,000. These grants may be made to local government, a utility or an irrigation district, and to cooperatives, nonprofits, or limited-dividend associations in rural areas. $20 million per year for the years 2006 through 2012 is authorized to aid small communities to increase the efficiency of, or upgrade transmission and distribution lines. This allocation of funding may also be used to upgrade generation facilities. Preference is given to renewable energy facilities.

There are 1,378 such counties with towns less than 10,000 people in the United States that may benefit from these funds [4]. If each of these communities made use of an equal amount of this funding that would be approximately $14,500 per rural community per year, or a total of little more than $100,000 per rural community over the 7 years involved.

Not all of these communities, however, will have generation. Most will have distribution systems that may benefit from upgrading. Many communities of this size do have small power plants, constructed in the 1930s, that will benefit from modernization. Some of these are hydroelectric power plants (fueled by renewable energy) and would have preference in funding, according to this bill.

III. DISTRIBUTED GENERATION

The Secretary of Energy in consultation with the Federal Energy Regulatory Commission (FERC) is instructed by the bill to conduct a study of the potential benefits of cogeneration and small energy production. They are instructed to study amongst others the effect of distributed generation on system reliability, power quality, reduction of peak power requirements, the supply of reactive power, the potential for emergency power and vulnerability to terrorism, the effect on land use, and effect on rates.

Funds are also authorized for research, development, demonstration, and commercial application of distributed energy resources, including improved system reliability and efficiency. $240 million is allocated in 2007, $255 million in 2008, and $273 million in 2009 for these programs. Included in these grants are projects including advanced energy delivery technologies, energy storage technologies, reliability and efficiency technologies, metering, load management and control, the supply of electricity to the grid by residential-based generators, and the development of grid design and planning tools.

In addition, $20 million is allocated in 2008 and 2009 which will be used to make competitive grants for the development of micro-generation technologies. These grants are to be used to explore the use of small-scale combined heat and power (CHP) in residential heating appliances, the use of excess power to operate residential appliances, and the supply of excess energy to the power grid.

The bill authorizes $6 million per year in matching funds to investigate power related issues on islands including the use of renewable sources to replace imported fossil fuels for the generation of electricity. An additional $500,000 per year is allocated for feasibility studies and $4 million per year is authorized for project implementation. These grants are to be used specifically for reducing dependence on fossil fuels and providing distributed generation in insular areas.

$20 million per year for 2006 through 2008 is available for grants to private, not-profit community development organizations, local governments, and Indian tribe economic development entities, in low income communities. These grants may be used to develop alternative, renewable, and distributed energy supplies, develop co-generation projects, or increase efficiency in buildings and facilities or institute energy efficiency projects.

IV. INTERCONNECTION ISSUES AND "PURPA"

The Public Utility Regulatory Policies Act of 1978 (PURPA) has been credited for encouraging the increase in renewable generation in the U.S. and at the same time been blamed for requiring utilities to purchase expensive power generated from often undesirable low quality sources. The Energy Policy Act of 2005 revises PURPA in several very important ways.

PURPA defined two types of "Qualifying Facilities": (a) a qualifying cogeneration facility, and (b) a qualifying small power producer. PURPA then required utilities to purchase power from these qualifying facilities at the rate of their "avoided cost" for producing this power [5].

The Energy Policy Act of 2005 removes the requirement that utilities purchase this power under the condition that the qualifying facility has access to alternative auction-based or competitive long-term wholesale markets. The bill does not change the requirements for existing qualifying facilities, but will impact new facilities. The utility is also no longer obligated to enter into a new contract to buy (sell) electricity from (to) a qualifying facility if it has other markets where this energy can be sold (purchased), unless otherwise required to do so by State law. The utility is also allowed to recover "all prudently incurred costs" associated with the purchase of electricity from a qualifying facility.

The bill also states that new rules will be formulated to define new qualifying facilities to ensure that the thermal energy is used in a productive and beneficial manner, the energy output is used for industrial, commercial, or institutional purposes and is not intended fundamentally for sale to an electric utility, and reflects progress in the development of efficient electric energy generating technology.

The removal of the utilities obligation to purchase power at their "avoided cost" and the requirement that the new qualifying facility sell power into the wholesale power market will undoubtedly have a huge impact on future such new facilities. In some areas the interpretations of a utility's "avoided costs" have resulted in a utility being required to purchase power far above market rates. One requirement for a facility being considered a "qualifying small power production facility" is that it uses some renewable source as its primary energy. Selling electricity at market rates instead of a utility's avoided costs may make some facilities uneconomical. Forcing a utility to purchase power at higher than market rates can only force the price of electricity up for the end consumer. The change to requiring qualifying facilities to sell power at market rates should tend to lower energy prices and force uneconomical projects out of the market.

The second change to PURPA is a requirement that every utility make available to every customer on their system the ability to interconnect an on-site generation facility. The utility is also required to make available to any electric consumer net metering service. Net metering is defined as a service under which energy from an on-site generating facility is delivered to the distribution system to offset the electric energy used by the consumer. Not only must net metering be provided, but at the consumer's request the utility must install "smart metering". Smart metering is time based. This allows the changes in wholesale electricity rates, which utilities see from peak to off-peak times, to be passed on to the customer. If the utility pays a different rate for electricity during different periods of time, then the bill requires that this be passed on to the customer to "enable the electric consumer to manage energy use and cost through advanced metering and communications technology" [1]. This type of metering could be advantageous to residential consumers with PV facilities. A utility may have a higher rate during the day when PV systems are at their peak production, and a lower rate at night when many residential customers use much of their power. This will allow a residential PV user to not only offset their electrical usage, but the power they used may be billed at a lower rate than the power they sell. This could make the size of the PV system required to just offset the cost of electrical usage smaller than would be required if time-based metering were not used. Installing time-based metering may make the installation of PV systems somewhat more cost effective but may have the opposite effect on renewable sources such as wind which may produce the most power at off-peak times.

These requirements in the bill are certainly encouraging distribution level generation. This raises some concerns. The first is the effect on the safety and security of the distribution systems and sub-transmission systems which were not originally designed for two-way power flow. As long as distribution level generation remains small and uncommon, the problems may be few and easily ignored. However, if distributed generation becomes common and makes up a significant part (estimated by many at 20% or higher) of the power flow over existing distribution systems problems will arise.

The desire has been expressed by those promoting small power production facilities that something be done to make interconnection with utilities "plug and play"[6]. The existence of some type of plug and play interconnection box that could be placed between a small generator and the distribution system that would ensure the safety of both the generator and the distribution and sub-transmissions systems would certainly be useful and make interconnecting distributed generation easy. However, distribution systems and their attendant protection requirements are so varied, and the effect of a certain generating source on any particular system so unpredictable without understanding each system individually, that producing such a "plug-and-play box" will be difficult [7].

In order to keep the distribution systems as reliable and safe as they are now it is likely that the addition of any distribution level generator must be examined by a distribution planning engineer and a protection engineer. At some point modifying protection requirements on the distribution system will certainly become necessary, and this may be true with the addition of the first generator on the system. Who will pay for such modifications is not spelled out clearly in the bill? The cost of having an engineer consider the impacts of each small generator on the system, and the cost of upgrading and changing the protection on the system or operation of the system (such as modifying re-closing) could exceed the total cost of the generation facility itself or as a minimum would raise the cost of the plant significantly.

The bill specifically states that interconnection services be based upon the IEEE Standard 1547: IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems [8]. It also states that "agreements and procedures shall be established whereby the services offered shall promote current best practices of interconnection for distributed generation, including but not limited to practices stipulated in model codes adopted by associations of state regulatory agencies. All such agreements and procedures shall be just and reasonable, and not unduly discriminatory or preferential." [1].

Three standards are listed for controlling distributed generation interconnections: (1) IEEE Std. 1547, (2) Model Codes, and (3) other procedures established to promote current best practices, which may include each utility's interconnection standards.

Model codes such as The National Electrical Code aptly address the method of safely installing various types of equipment including generation facilities. However these codes, in general, do not adequately address protection of the interconnection point itself, the generator, or the distribution system.

IEEE Std. 1547 defines interconnection as "The result of the process of adding a DR (Distributed Resource) unit to an Area EPS (Electric Power System)."[8] IEEE Std. 1547 mainly concerns itself with the interconnection point and protecting the distributed resource from abnormal grid conditions and the system from some of the predictable effects of the distributed resource on the distribution system. It specifies synchronization and power quality requirements, and methods of preventing islanding of the distributed resource. The standard gives requirements that shall be met at the point of common coupling or DR connection and states that it: "does not address planning, designing, operating, or maintaining the area electric power system (EPS)" [8].

From an engineering standpoint the most complex and variable part of adding generation to the distribution system and the impact of the DR on the distribution system, is left to "other agreements and procedures" which will presumably include utility interconnection rules. These rules must consider the impact of the distributed resource on other customers of the utility's system and the safety and reliability of the system itself. Utility interconnection guidelines may sufficiently address the impact of generation on the distributions system, however, none of the standards spelled out in the energy bill are sufficient to consider the effects of the DR on other customers.

For example, consider the common condition of 4 homes fed from the secondary side of a single-phase distribution transformer. The short circuit interrupting values of equipment in residences is often marginally designed based upon the impedance of the distribution transformer. If one of the customers decides to add some type of distributed generation to their home on the secondary of this transformer the short circuit current availability to all the other homes connected to the transformer may increase as a function of the type and size of generation installed. If the new short circuit value exceeds the interrupting rating of the protective equipment in the other homes their existing systems will become unsafe due to the inability of their breakers to interrupt the new short circuit current. Neither IEEE 1547, the National Electrical Code, nor most utility interconnection guidelines address all the problems that may be created in the residences of other customers by the addition of distribution level generation.

On a larger scale, consider a 7.5/10 MVA substation transformer supplying a sub-division with 4,500 residential homes with average electrical usage of 1 kW each and 1.8 kW peak usage. If 2/3 of the homes decided to take advantage of the energy bill's provisions and install just enough PV systems to offset all their energy use each of these 3,000 homes would have to install a 6.7 kW PV system assuming a capacity factor of 15%. At noon on a sunny day when all systems were operating at peak output the distributed generation on this system total 20.1 MW or 23.7 MVA at 0.85 pf (since the utility would still have to supply the system VARS). Even if the distribution system peak load happened to coincide with the output of the PV systems there would still be 14.1 MVA being delivered through the 7.5/10 MVA transformer to the sub-transmission system. Clearly this condition would require the utility to upgrade the transformer and make protection modifications. Additionally, if the users of the distribution systems generated just enough power to offset their usage using a source like PV, the utility would be in the unenviable position of still having to maintain and upgrade the distribution infrastructure, maintain enough conventional sources of generation to supply all electrical needs during the times when the PV systems could not supply the distribution system load, while at the same time not generating any revenue from selling electricity on the system.

It is often argued that the addition of distributed generation will reduce demands on distribution and transmission systems. This may be true in the short run, however, if distributed generation becomes a major part of the energy generated the demands on distribution and transmission systems may increase depending on the characteristics of the distributed generation.

V. CONCLUSION

The Energy Policy Act of 2005 authorizes a grand total of $800 million for various types of distributed generation projects and research. The major effect the bill on distributed generation, however, will come due to changes in PURPA.

The changes to PURPA are important and may make access to distribution level interconnection and metering easier for residential and commercial users who are inclined to install their own generation. However, it remains for the utilities to establish interconnection guidelines for distribution level generation. The Energy bill requires the use of IEEE Std. 1547 as one part of the necessary requirements for interconnecting distributed resources and several utilities and independent system operators have included it in their standards for handling the interconnection requirements for DR often along with additional utility requirements and testing requirements. A single standard that could be applied to any distributed resource interconnection is desirable and IEEE Std. 1547 is a start in producing additional standards for the point of common coupling. However, work should be done to expand into a single comprehensive standard that would include all types of changes which might be necessary when generation is added to distribution systems. This should include requirements at the point of common coupling, effects and remedies for problems produced by distributed generation on other distribution customers, and other requirements that can be adopted by utilities as complete interconnection standards for distribution level generators. This will be a difficult and complex process due to the variety of conditions and types of distribution systems across the United States, but a single guideline which could be applied to the many common types of distribution systems would be useful.

Utilities have historically established their own guidelines for generation interconnection, and these guidelines often vary from one utility to another. Two different utilities may have somewhat different standards which a power plant wishing to interconnect must meet. These differences between utilities often reflect preferences of protection and planning engineers rather than any real technical differences in their respective power systems. This can lead to difficulties and confusion for power producers doing advanced planning and engineers who are designing the interconnection. A single standard which could be implemented by all utilities and would describe interconnection requirements for each type of distribution system would be helpful, and was one reason behind the development of IEEE Std. 1547. IEEE Standards Coordinating Committee (SCC) 21 is currently addressing these issues with a series of standards and guides [9][10].

Finally, The Energy Bill of 2005 is an authorization bill only. At the time this paper is being written, the "Appropriations Bill" which will appropriate the spending of these funds for the next year has not yet been passed. It will be interesting to see what funds authorized in this bill are actually appropriated, and track the effects of this funding on distributed generation in the future.

VI. REFERENCES

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VII. APPENDIX

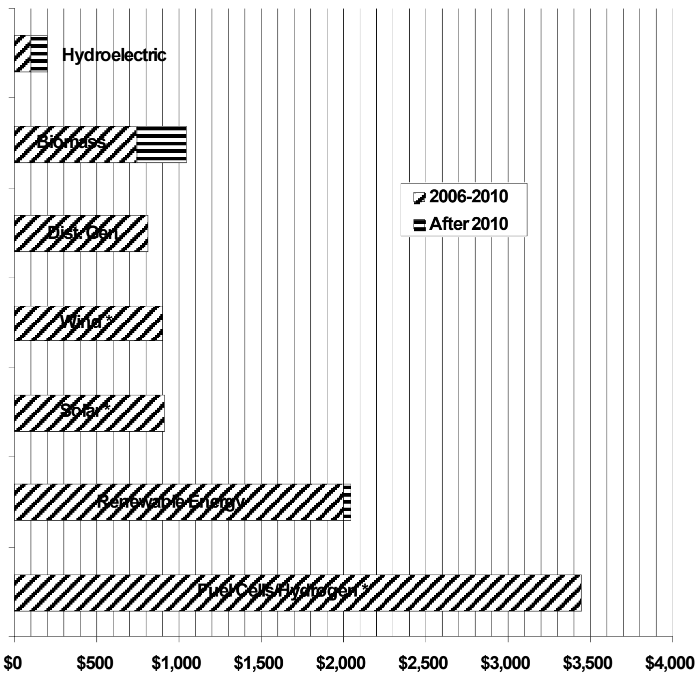

Fig. 6 Summary of Authorizations in Millions of Dollars
*** Funds "As Needed" are to be appropriated after 2010**
Note: There is some crossover between categories. Some funds for wind, solar, and renewable energy are also dedicated to hydrogen production.

OTHER FUNDS NOT SHOWN IN FIGURE 8		
ENERGY TYPE	**AUTHORIZATION**	**YEARS**
Federal Purchase of Renewable Energy	3% of all electricity used	2006-2007
	5% of all electricity used	2010-2012
	7.5% of all electricity used	2013 onward
Residential Installation of PV	Up to $2000.00 tax credit	2006-
Commercial Installation of Microturbine	Up to $200.00/kW Tax Credit	2006-2007
Integrated Coal and Wind Projects	Loan Guarantees	
Residential or Commercial Installation of Fuel Cells	Up to $500.00 /per ½ kW tax credit	2006-
Residential/Commercial Hydrogen Fuel Cell Projects	Loan Guarantees	

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