Oil and Natural Gas Market Supply and Renewable Portfolio Standard Impacts of Selected Provisions of H.R. 3221

November 2007

This paper responds to an October 31, 2007, request from Representatives Barton, McCrery, and Young. Their letter, a copy of which is provided as Appendix A, asks the Energy Information Administration (EIA) to assess selected provisions of H.R. 3221, the energy bill adopted by the House of Representatives in early August 2007. EIA was asked to focus on Title VII, dealing with energy on Federal lands; Section 9611, which would establish a Federal renewable portfolio standard (RPS) for certain electricity sellers; and Section 13001, which would eliminate the eligibility of oil and natural gas producers and refiners to claim deductions under Section 199 of the Internal Revenue Code.

To facilitate an expedited response, this paper is organized around the main issues raised in the request. The first section addresses Title VII and Section 13001, the provisions of H.R. 3221 with the most direct impact on oil and natural gas supply. Since these provisions are generally not amenable to analysis using the modeling tools available to EIA, their potential impact is addressed by placing them in the context of the recent oil and natural gas domestic production and financial data and available projections of onshore and offshore production from Federal lands. Our review suggests that these provisions likely would have some negative impact on the pace of domestic oil and natural gas drilling activity and refinery investments, but we are unable to quantify those effects. Taken alone, these provisions would tend to increase reliance on oil imports and raise natural gas prices.

The second section of the paper presents an analysis of Section 9611, which is similar in many respects to RPS proposals that have previously been analyzed by EIA. Our analysis shows that the RPS, taken alone, tends slightly to increase projected electricity prices and costs by 2030, while tending to reduce the use of natural gas for electricity generation and natural gas prices. Cumulative discounted residential energy expenditures through 2030, which are projected to total $2,874 billion in the reference case, are unchanged or fall slightly, with a reduction of approximately $400 million (.01 percent) in one of the two RPS cases modeled.

Title VII and Section 13001: Assessment of Oil and Natural Gas Supply Impacts

Title VII

Title VII contains several provisions[1] that would generally lengthen timelines and add new procedural requirements for leasing and producing energy on Federal lands. Subtitle A would repeal subsections 365(g) and 365(i) of the Energy Policy Act of 2005 (EPAct2005) regarding recovery of permit processing costs. It would require the Secretary of the Interior to impose fees on the oil and natural gas industry to recover costs associated with the streamlining of permits

[1] Title VII provisions affecting the oil and natural gas industries are summarized in the following two paragraphs, which are taken almost verbatim from *Energy Policy Reform and Revitalization Act of 2007, Title VII of H.R. 3221: Summary and Discussion of Oil and Gas Provisions,* CRS Report RL34111, August 2008.

during the pilot project established by EPAct2005 to improve Federal permit coordination. A new 45-day deadline would be imposed for the consideration of applications for permits under section 366 of EPAct2005. Section 369 of EPAct2005 would be amended by removing two deadlines related to oil shale research and development and the preparation of a final environmental impact statement for commercial oil shale and tar sands leasing on public lands. H.R. 3221 would limit section 390 of EPAct2005, which allows for a rebuttable presumption regarding the application of categorical exclusions under the National Environmental Policy Act (NEPA) for oil and natural gas exploration and development activities. A best management practices provision would require the Bureau of Land Management to allow for public comment and review before lease stipulation waivers are granted.

Subtitle B would require a minimum of 550 audits annually and increase fines for royalty payment violations under the Federal Oil and Gas Royalty Management Act of 1982. Surface owner protection would be enhanced under split estates where the Federal government owned and leased minerals. Additional requirements for the protection of water resources are included and new fees would be assessed to lessees of Federal lands as a disincentive to hold and not develop those lands. Onshore oil and natural gas reclamation requirements would become more stringent. Provisions in Subtitle F would establish an Oil Shale Community Impact Assistance Fund and prohibit surface occupancy on Federal leases on top of the Roan Plateau in Colorado.

EIA does not specifically model procedural features of the oil and natural gas leasing program, but any program changes that lengthen timelines, add new procedural hurdles, require additional negotiations and accommodations with surface owners, or otherwise add to cost, likely would delay oil and natural gas leasing and production projects and also make marginal projects less attractive to pursue. The provisions considered above generally fall into these categories, so some adverse impact on oil and natural gas leasing and production would be expected. EIA cannot quantify this effect using the modeling tools available to it, as mentioned previously.

Table 1 places onshore and offshore oil and natural gas production for 2006 in the context of total U.S. production and consumption of these energy sources. Looking forward, production from Federal lands is expected to play an increasingly important role in total U.S. oil and natural gas production over time. In 2006, roughly 35 percent of U.S. oil production and 30 percent of domestic natural gas production were from Federal lands. Over the next 10 years the share of production from Federal lands is projected to increase to 47 percent for oil and 37 percent for natural gas (**Table 2**).

Continued exploration and development of offshore crude oil and natural gas resources are critical to attain the projected production increases from Federal lands. The vast majority (85 percent) of Federal crude oil production from 2008 to 2017 is projected to come from the offshore, with 80 percent from the Gulf of Mexico, 4 percent from Alaska, and 1 percent from the Pacific regions. Projected Federal offshore natural gas production is significant as well, growing from 53 percent to 60 percent of total Federal natural gas production between 2008 and 2014.

Table 1. Oil and Natural Gas Production from Federal Lands in Perspective, 2006

	Petroleum (million barrels)	Natural Gas (trillion cubic feet)
Production from Federal Lands	600.5	5.0
Onshore	100.4	2.1
Offshore	500.1	2.9
Other U.S. Production	1,261.8	13.5
Total U.S. Production	1,862.3	18.5
Total U.S. Consumption	7,550.9[a]	21.9

[a] Represents total liquid fuels consumption and includes ethanol. Crude oil is refined to produce a wide array of petroleum products, including heating oils; gasoline, diesel and jet fuels; lubricants; asphalt; ethane, propane, and butane; and many other products used for their energy or chemical content.
Source: **Federal Onshore Production**: Minerals Management Service, Minerals Revenue Management, MMR WebStats, Federal Onshore Reported Royalty Revenues; **Total U.S. and Federal Offshore Oil Production and Total U.S. Petroleum Products Consumption**: Energy Information Administration (EIA), *Petroleum Supply Annual 2006*, DOE/EIA-0340(2006) (September 2007); **Total U.S. and Federal Offshore Natural Gas Production**: EIA, *Natural Gas Annual 2006*, DOE/EIA-0131(2006) (October 2007); **U.S. Natural Gas Consumption**: EIA, *Annual Energy Review 2006*, DOE/EIA-0384(2006) (June 2007).

Table 2. Projected Trends in Oil and Natural Gas Production on Federal Lands, 2008-2017

Year	Oil (million barrels)		Natural Gas (trillion cubic feet)	
	Offshore	Onshore[a]	Offshore	Onshore[a]
2008	672.0	121.5	3.3	2.9
2009	703.6	127.5	3.6	2.9
2010	717.9	132.9	3.6	2.9
2011	758.2	137.0	3.8	2.9
2012	795.1	140.6	3.9	2.9
2013	782.4	143.0	4.0	2.9
2014	821.3	146.0	4.3	2.9
2015	850.3	147.8	4.3	2.9
2016	862.3	149.6	4.3	3.0
2017	865.7	151.4	4.3	3.0

[a] Federal onshore production is not explicitly represented in the National Energy Modeling System. The volumes are estimated based on historical trends and the projected regional production from the reference case of the *Annual Energy Outlook 2007*.
Source: Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (February 2007).

Section 13001

Section 13001 of the bill would deny a deduction for income attributable to domestic production of oil, natural gas, or primary products thereof that is currently available under Section 199 of the Internal Revenue Code. Under current tax law, the deduction from taxable income or, in the case of an individual, adjusted gross income, is equal to a portion of the taxpayer's qualified production activities income. For taxable years beginning in 2007, 2008, and 2009, the deduction is 6 percent of such income. For taxable years beginning after 2009, the deduction is 9 percent. The deduction in any taxable year is limited to 50 percent of the wages properly allocable to domestic production gross receipts paid by the taxpayer.

The Joint Committee on Taxation (JCT) estimates that Section 13001 would increase revenues by over $300 million in Fiscal Year (FY) 2008. With the scheduled increase in deductions under current law, the estimated revenue impact grows to nearly $1.1 billion by FY 2010. Projected cumulative revenue impacts through FY 2012 and FY 2017 are $4.2 billion and $11.4 billion, respectively.

EIA, which has no access to tax return information, is not able to develop an independent estimate of revenue impacts or to perform a tax incidence analysis. We can, however, place the JCT revenue impact estimates in the context of income for the oil and natural gas production and refining sectors, based on data for large energy companies collected through the EIA Financial Reporting System (FRS). In 2006, the FRS companies accounted for 44 percent of U.S. oil production, 43 percent of U.S. natural gas production, and 81 percent of U.S. refining capacity.

In order to place revenue impacts in the context of total income for the affected oil and natural gas activities, an income estimate that encompasses all producers and refiners, not just the FRS companies, is required. Absent a basis for assuming differences in income per unit of activity between FRS and non-FRS producers, total oil and natural gas producer income is estimated by multiplying FRS producers' income by the ratio of total domestic production to FRS companies' production. To make this calculation, oil and natural gas data are aggregated based on their respective wellhead values per unit of production. A similar approach for refining is to develop income estimates that include non-FRS companies.

Table 3 reports FRS data for 2001 through 2006, together with income estimates that encompass non-FRS companies based on the calculations described above. Income from oil and natural gas production has risen steadily over the period, reflecting generally rising prices for both oil and natural gas. Table 3 also illustrates that earnings from refining are highly variable over time. The revenue estimate of an average of $1.1 billion per year between 2008 and 2017 for Section 13001 would equal between 1 and 4 percent of after-tax income compared to the values in Table 3 for oil and natural gas production and refining combined from 2001 to 2006.

Table 3. FRS and Estimated Industry Income for Producers and Refiners, 2001-2006 (million current dollars)

	2001	2002	2003	2004	2005	2006
FRS Oil and Natural Gas Production Income						
Income Before Taxes	$27,287	$21,304	$34,604	$46,955	$63,511	$64,783
Income After Taxes	$17,646	$15,030	$22,630	$30,146	$40,496	$41,286
FRS Refining/Marketing Income						
Income Before Taxes	$18,222	-$1,283	$11,599	$22,777	$32,178	$37,363
Income After Taxes	$11,951	-$1,350	$7,434	$15,197	$20,963	$24,313
Estimate of Oil and Natural Gas Production Income, all Producers						
Income Before Taxes	$58,817	$45,339	$76,845	$106,498	$146,845	$149,772
Income After Taxes	$38,036	$31,987	$50,255	$68,373	$93,631	$95,449
Estimate of Refining Income, All Refiners						
Income Before Taxes	$20,010	-$1,455	$13,462	$25,913	$36,284	$42,844
Income After Taxes	$13,124	-$1,531	$8,628	$17,289	$23,638	$27,880
Estimate of Income, all Producers and Refiners						
Income Before Taxes	$78,828	$43,884	$90,307	$132,410	$183,129	$192,616
Income After Taxes	$51,160	$30,456	$58,883	$85,663	$117,270	$123,329

FRS=Financial Reporting System.
Source: Energy Information Administration.

Section 9611, the Renewable Portfolio Standard

Section 9611 of H.R. 3221 would establish a Federal RPS requiring that 15 percent of covered U.S. electricity sales be derived from qualifying renewable resources by 2020. The requirement is phased in beginning in 2010, and it expires in 2039. A covered retail electric supplier's existing generation from hydroelectric and municipal solid waste (MSW) is excluded from the sales baseline when determining the required renewable generation level. All public power sellers and rural electric cooperatives, as well as small suppliers with sales below 1 billion kilowatthours per year, are exempt from the program.

The RPS program provides several alternative compliance strategies in addition to generating electricity using eligible renewable sources. Covered retail sellers can trade renewable energy credits to achieve compliance, with one credit awarded for every kilowatthour of qualifying renewable generation, except for distributed renewable installations, which receive three credits per kilowatthour, and installations on Indian lands, which receive two credits per kilowatthour. Up to 25 percent of the renewable generation requirement can come from qualified energy efficiency credits. Compliance credits can also be purchased from the Federal government at 3 cents per kilowatthour, effectively capping the price of tradable credits at that level and allowing a compliance option in lieu of additional qualifying renewable generation or energy efficiency credits.

The combined effect of the hydropower and MSW exclusions and the exemptions for public and small electricity suppliers is to reduce the effective target, as measured by the required share of all electricity sales to be met with eligible renewable sources or qualified energy efficiency credits, to between 10 and 13 percent in 2030[2]. The results in this analysis are based on a target schedule that achieves an effective 11.3-percent target share by 2030[3]. Because of the potential use of energy efficiency credits, the renewable-specific target could be as low as 8.5 percent, with the remaining 2.8 percent of the target being met with efficiency credits. Finally, the allocation of triple credits to distributed renewable installations potentially pushes the share of actual renewable generation below 8 percent of sales in some years.

EIA's analysis of Section 9611 suggests that credit prices remain below the government credit cap[4] throughout the forecast period and generally below credit prices projected in the recent EIA analysis of the 15-percent RPS proposal of Senator Bingaman[5]. With a 2039 sunset date, in contrast to the 2030 sunset in the Bingaman proposal, renewable generators have a longer time to recover any above-market costs associated with renewable generation. This allows them to amortize the costs over a longer period of time and reduces the per-kilowatthour impact of these costs.

In addition to the underlying uncertainties inherent in the modeling of any RPS proposal, which are discussed in EIA's recent report on the Bingaman proposal, the nature of the RPS proposal in Section 9611 and the time constraints for conducting this analysis introduce additional uncertainty. As noted previously, EIA was not able to fully assess the target requirement in terms of qualified renewable generation as a share of all electricity sales, which is the primary measure of interest with respect to EIA's energy model. Although the range is somewhat narrow and generally centered around the target calculated for the Bingaman proposal, results would likely change with different assumptions. A slightly higher target level–if, for example, a significant amount of hydroelectric generation was sold at retail by public suppliers–would result in somewhat more renewable generation and a somewhat higher credit price. A slightly lower target would result in reduced renewable generation and lower credit prices, although EIA would expect the overall trends observed to be very similar.

Also, retail electricity price impacts in EIA's model are not currently represented in accordance with the different requirements for public and private retailers in the Section 9611 RPS. Currently, price impacts assume equal distribution of price impacts among all retail suppliers in each region, but under the Section 9611 RPS program, private suppliers would bear the entire price impact, and public utilities and cooperatives would not see any price impact.

The provision to allow energy efficiency credits also adds uncertainty. The provision requires the governor of each State to make a separate application for the provision to apply in his or her

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[2] This range reflects uncertainty in the amount of hydroelectric generation sold by public suppliers and the possible impacts of the RPS proposal on the relative growth of private and public suppliers. The low-end estimate is based on the assumption that sales from public utilities grow at the same rate as private retailers through 2030 and that all existing hydroelectric generation is sold by private retailers. The high-end estimate is based on the assumption that public suppliers do not grow through 2030 and that all existing hydropower is sold by public suppliers.

[3] This assumes no public utility growth and that all hydroelectric generation is sold by public suppliers.

[4] The credit prices in HR 3221 are expressed in current dollars but allow for an inflation adjustment. The results are expressed in real, inflation-adjusted, 2005 dollars.

[5] Energy Information Administration, *Impacts of a 15-Percent Renewable Portfolio Standard*, SR-OIAF/2007-03 (June 2007), http://www.eia.doe.gov/oiaf/servicerpt/prps/index.html.

State. There appears to be some room for interpretation of qualifications to earn the efficiency credits, and a significant opportunity may exist for "free riders," that is, those who earn credits by taking actions they would have taken absent the incentive. If one believes that no States will apply for this provision or efficiency credits will only result in incremental efficiency investments–that is, investments that would not have occurred without the provision–then the final renewable generation share would be larger than with the Bingaman RPS proposal previously analyzed by EIA. If one believes that States will maximize use of the efficiency credits and that these credits will primarily be awarded to free riders, then the resulting generation share would be approximately the same, if not slightly lower, than the final renewable generation in the Bingaman proposal, accounting for triple photovoltaic credits and credits purchased from the Federal government. A larger renewable share would result in more displacement of coal and natural gas and be likely to lower prices for these commodities. Given the significant impact on the effective renewable-specific target, EIA examined two cases with assumptions at two extremes. In **Table 4** below, the RPS A case assumes that efficiency credits will be claimed to the maximum extent possible and will not result in significant sales reductions from the reference case projections in the *Annual Energy Outlook 2007* (*AEO2007*).[6] The RPS B case assumes that no efficiency credits will be claimed.

The results for the two RPS cases, presented in Table 4, show that the RPS tends to reduce projected natural-gas-fired electricity generation compared to the *AEO2007* reference case. In 2020, impacts on electricity prices range from a decrease of 0.3 percent in the RPS A case to a 0.4-percent increase in the RPS B case, when compared to reference case prices. At the same time, impacts on Henry Hub natural gas prices are within 2.5 percent of annual reference case prices, with overall natural gas prices being lower in the RPS cases. There is almost no projected change in cumulative discounted energy expenditures by residential consumers through 2030. In the RPS A case, where efficiency credits are fully utilized, cumulative discounted expenditures are approximately $400 million lower. However, the RPS tends to increase residential energy expenditures late in the forecast period. In 2030, residential energy expenditures are $1 to $2 billion, or roughly 0.4 percent to 0.8 percent, higher with the RPS. The RPS is estimated to reduce carbon dioxide emissions from electricity generation by between 5 and 8 percent in 2020 and by 4 to 7 percent in 2030.

Finally, it should be noted that the RPS proposal was modeled on a standalone basis, so its possible interactions with other policy changes proposed in H.R. 3221 or other bills were not considered. For example, proposals to increase the use of transportation fuels derived from biomass could increase competition for the biomass supplies utilized in this analysis to comply with the RPS targets.

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[6] Energy Information Administration, *Annual Energy Outlook 2007*, DOE/EIA-0383(2007) (February 2007).

Table 4. Key Indicators in the Reference Case and Two H.R. 3221 RPS Cases, 2020 and 2030

	2005	2020			2030		
		Reference	RPS A	RPS B	Reference	RPS A	RPS B
Natural Gas Generation (bkwh)	752	1059	1009	993	932	946	916
Total Natural Gas Use (tcf)	22.0	26.3	25.9	25.8	26.1	26.2	26.0
Natural Gas for Generation (tcf)	5.8	7.2	6.9	6.7	5.9	6.0	5.8
RPS Credit Price (cents/kwh)	n/a	n/a	1.62	2.34	n/a	0.69	0.91
Natural Gas Price at Henry Hub ($/mmbtu)	8.60	5.71	5.63	5.58	6.52	6.51	6.47
Residential Natural Gas Price ($/mmbtu)	12.80	10.86	10.78	10.72	11.77	11.77	11.71
RPS-eligible Generation[a] (bkwh)	84	177	365	484	203	395	529
Total Sales (bkwh)	3660	4528	4530	4524	5168	5144	5138
Electricity Price (cents/kwh)	8.1	7.9	7.9	7.9	8.1	8.2	8.1
Carbon Dioxide Emissions from Generation (mmt)	2,375	2,832	2,703	2,608	3,338	3,201	3,112
Residential Energy Expenditures (billion 2005 dollars)	$215	$236	$236	$236	$262	$264	$263
Cumulative Residential Energy Expenditures (billion 2005 dollars discounted at 7 percent)[b]	$215	$2,241	$2,239	$2,240	$2,874	$2,873	$2,874

Notes: bkwh = billion kilowatthours, tcf = trillion cubic feet, $/mmbtu = 2005 dollars per million Btu, cents/kwh = 2005 cents per kilowatthour, mmt = million metric tons.
RPS A assumes maximum utilization of energy efficiency credits with no corresponding reduction in sales.
RPS B assumes that energy efficiency credits will not be used.
[a]This refers to actual generation. Credits earned would be somewhat more, since distributed resources, such as most photovoltaics, would earn three credits for every kilowatthour generated. Generation projections from the reference case of the *Annual Energy Outlook* are for comparison purposes only and refer to generation that would be eligible under the rules of the RPS.
[b]Represents the sum of annual residential energy expenditures for 2005 through 2030, discounted back to 2005.

Source: Energy Information Administration, National Energy Modeling System runs: aeo2007.d112106a, hrps15hy.d111407a, hrps15hy.d111407b.

Appendix A

Request Letter

Congress of the United States
Washington, DC 20515

October 31, 2007

The Honorable Guy F. Caruso
Administrator
Energy Information Administration
1000 Independence Avenue, SW
Washington, DC 20585

Dear Mr. Caruso:

We write to request that you conduct a quantitative analysis of the impact of Speaker Nancy Pelosi's energy bill (H.R. 3221) on domestic oil, natural gas, gasoline and diesel supplies and prices. We are deeply concerned that rising energy prices threaten family budgets and jobs, and we believe more of our energy supplies should be produced at home. The Energy Information Administration's analysis would be a useful metric for measuring whether the bill meets these tests, making this the first objective analysis of the bill. With energy prices approaching real all-time highs, we believe the responsibility of Congress is to "first, do no harm" to energy availability and/or price.

Specifically, we ask that your analysis focus on Title VII and Sections 9611 and 13001. While we would like the Energy Information Administration (EIA) to undertake a broad review of the energy and economic impacts of these specific provisions, please identify if any provision will actually increase the domestic supply of oil, natural gas, gasoline and diesel thereby reducing price. We are concerned that none does. Rather, we anticipate the opposite effect. That is why we ask for your analysis.

Please contact Maryam Sabbaghian at (202) 226-3211, with any questions.

We appreciate your guidance and assistance. The Energy Information Administration has made key contributions to discussion and understanding of energy issues. The objective analysis we request will greatly help the Congress in its understanding of national energy policy.

Sincerely,

Don Young
Ranking Member
Committee on Natural Resources

Jim McCrery
Ranking Member
Committee on Ways and Means

Joe Barton
Ranking Member
Committee on Energy and Commerce