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Economic impacts and framework conditions for potential unconventional gas and oil extraction in the EU

Case studies of Germany and Poland

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Economic impacts and framework conditions for potential unconventional gas and oil extraction in the EU. Case studies of Germany and Poland

This study assesses the potential economic impacts of unconventional hydrocarbon investment projects in two European countries: Poland and Germany. The analysis carries out a profitability assessment of the investments, the potential job creation in the region where the activity takes place and the public finance in terms of royalties paid to the local and national governments.

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Foreword

This report is part of the consultancy service provided by Advanced Resource International, Inc. 4501 Fairfax Drive, Suite 910, Arlington, VA 22203 for the Joint Research Centre Directorate C for Energy, Transport and Climate within the tender JRC/PTT/2015/F.3/0119/NC titled "*Study for country wide economic impacts and framework conditions for potential unconventional gas and oil extraction in the EU. Country study: Germany and Poland*".

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Executive Summary

Introduction. The development of new unconventional hydrocarbon (UH) resources has the potential to bring economic benefits to EU Member States. The purpose of this effort is to assess the potential benefits associated with the possible development of new UH resources in Poland and Germany.

A number of important factors for characterizing these potential benefits were considered. Cost and resource deployment estimates are specifically tied to the resource characteristics in Poland and Germany, as best those are known at this time. New UH resource productivity and economics account for increased resource understanding, technology evolution, and improvements in efficiency that takes place over time and as development in a play evolves. Benefits characterizations are performed at two points in the maturity of an UH resource play: when exploration, development, and production initiates (with mostly non-local personnel); and as development in the play matures (with most personnel locally based). Finally, best environmental practices based on the U.S. experience, and the corresponding costs, are assumed.

At the heart of the debate about the future outlook for new UH resources in Europe, consistent with that which has taken place in North America, is the pace and ability to find the most productive areas of a play – the so-call "sweet spots" -- which often represent a very small portion of the total area of a play.

For both Poland and Germany, a potential future "sweet spot" with modest productivity was posited in a potential "yet be discovered" region as a result of future exploration drilling. Estimated ultimate recovery (EURs) values for fractured horizontal oil and/or gas wells for a Base Case (most likely), Low and High Case were developed.

Key conclusions. The economic assessment concluded that, in both countries, commercial viability would likely not be achievable under the Low or Base Case EUR. Only if EURs approach the High Case or higher, or resource development costs and/or government royalties are significantly reduced, can economic viability be achieved. Thus, the estimated benefits will only be fully realizable if per well productivity exceeds that associated with the Most Likely Case EURs, and only in areas defined as the "sweet spots." Given the recent experience in these two countries, this may be a challenge, at least in the near term.

Main findings. Given these caveats, economic and employment benefits for UH resource development and production were estimated for two phases of activity: (1) a site evaluation and initial exploration phase, and (2) (if pursued) a development and production phase.

Under the most aggressive development scenario considered, the following benefits for Germany or Poland were estimated to result during the site evaluation and initial exploration phase:

- 110 direct jobs and 330 indirect jobs (440 total) associated with drilling, of which 193 are local jobs, and 247 are expat or home office jobs.
- 125 jobs, of which 94 are local jobs, associated with site construction.
- Expenditures on drilling and site construction peak at € 67.5 million per year.
- Payment of € 37.6 million in salaries for the 369 local jobs created.
- Collection of € 10.8 million in income taxes from salaried workers in Poland, and € 14.2 million in income taxes from workers in Germany.

During the development and production phase, *assuming that the basin/play proceeds to this phase*, employment and economic benefits associated with a most aggressive, large-scale development scenario in Poland are:

- At full development, 1,800 wells are producing, with a peak production of 5.8 billion cubic meters per year

- Annual capital expenditures peak at nearly € 2 billion. As many as 9,700 local personnel are employed in development activities.
- Operating expenditures grow to over € 340 million annually; as many as 32,400 local personnel are employed in oil and gas operations.
- € 3.5 billion annually are earned in salaries by these personnel; for which, they eventually pay over € 1.1 billion annually in income taxes.
- Industry can earn as much as € 1.9 billion to € 2.9 billion annually; the government could earn as much as € 26 to € 44 million annually in royalties.

Similarly, highlights of the employment and economic benefit associated with a large-scale development scenario in Germany are:

- At full development, 600 wells are producing, with a peak production of over 1.5 billion cubic meters per year
- Annual capital expenditures for development drilling and facility construction peak at nearly € 325 million. As many as 3,300 local personnel are employed in these activities.
- Annual operating expenditures grow to nearly € 115 million; as many as 10,800 local personnel are employed in oil and gas field operations.
- € 1.2 billion annually are earned in salaries by these personnel; for which, they eventually pay nearly € 490 million annually in income taxes.
- Industry can earn as much as € 500 to € 800 million annually; the government could earn as much as € 150 to € 240 million annually in royalties.

Smaller and slower development scenarios were also considered and are described in the report.

Policy context. Two categories of potential challenges can impact new UH resource exploration and development. These can add to development and production costs, and adversely affect commercial viability: (1) Concession terms and the sharing of the proceeds of UH resource development and production with the government; and (2) Issues, and associated costs, related to addressing environmental concerns. Consideration of this category of issues is beyond the scope of this report.

In Poland, the oil and gas tax regime has been modified for UH resource development to encourage investment, with the government gaining most of its financial benefits when projects are sufficient profitable. Poland's Special Hydrocarbons Tax (SHT) is structured such that its applies at its maximum rate only when revenues sufficiently exceed expenses, and income taxes only apply if an operator is in fact generating positive cash flow.

Germany, on the other hand, imposes high royalties, such that the government takes its share "off the top," regardless of whether or not positive cash flow is being realized by the operator. This could stifle potential investment.

Introduction

The European Union (EU) is facing serious energy challenges with increasing dependency on imports of hydrocarbon fuels and related risks to security of energy supply, with impacts on energy prices, competitiveness, and on the effective completion of the internal EU energy market. Unconventional fossil fuels have attracted interest in some Member States as a possible new source of natural gas and oil. The recent boom in natural gas and crude oil production from shale formations (shale gas and tight or shale oil) in the US, otherwise referred to as unconventional hydrocarbons (UH)[1], has ignited a discussion on the European potential for shale gas and/or oil extraction and its economic and environmental implications.

The promise of new UH resources to contribute to security of supply has spurred several EU Member States to allow for exploration of domestic shale gas and oil on their territory. The exploration and development of new UH resources also have the potential to bring direct and indirect economic benefits to EU Member States from: investments in infrastructure; employment in the extraction industry or in related service industries; and government revenues from taxes and royalties on hydrocarbon production.

Purpose and Objectives of the Study

The purpose of this study is to provide an assessment of potential economic and employment benefits from exploration and development of newly developed UH resources in Europe. The countries selected as the focus of this initial effort are Poland and Germany.

In this study, the benefits associated with new UH resource development focus on the investment and impacts and government revenues. Based on the level of development, impacts on direct employment in the oil and gas industry, along with indirect employment resulting in other sectors, are also estimated. Estimation of impacts on the Gross Domestic Product (GDP), energy import dependency, and energy prices (oil, gas, and electricity) are beyond the scope of this effort.

The important features and considerations for characterizing and specifying country-wide economic impacts and framework conditions for potential new UH resource development and production in Germany and Poland are described below.

- **Importance of Resource Characteristics**. Published estimates of the UH resource potential in Europe cover a considerable range. Cost and resource deployment estimates in this study are specifically tied to the characteristics of the shale oil and gas resources in Poland and Germany, as best those resources can be characterized from information currently known. This builds upon previous work by Advanced Resources for the US Energy Information Administration (ARI, 2013), the first comprehensive geological assessment of shale oil and gas resources in Europe and globally. This pioneering work included individual assessments of shale resource plays in Germany and Poland. Based on these resource characterizations, and consistent with UH resource development in North America and elsewhere, the assessment of potential benefits is based on the assumption that only the highest quality/highest productivity areas of these plays – the so-called "sweet spots," which often represent a very small portion of the total area of a play -- are ultimately assumed to be developed.
- **Importance of Play Maturity.** Life cycle characterization is performed at two points in time in the maturity of a new UH resource play. The first is based on the point in time where exploration, development, and production initiates.

[1] In this report, unconventional hydrocarbons (UH), especially as they pertain to potential development in the future, primarily refers to shale gas and oil. However, the term UH also often includes other so-called unconventional resources, in particular, low permeability (tight) gas sands and coalbed methane (CBM). We attempt to make these distinctions where determined to be relevant.

This will be before an in-country industry and work force has been established, and a large portion of the services and personnel will be provided by expatriates or from a company's "home office." Over time, as development in the play matures, a greater portion of the services and employment will be provided by in-country (local) resources. Thus, the capital deployment, employment, and associated benefits will accrue more within the country. Proper accounting for this evolution of developmental maturity in a play is critical to the characterization of potential benefits.

- **Importance of Increased Resource Understanding, Technology Evolution, and Improvements in Efficiency.** The characterizations in this assessment of the UH resource productivity and economic potential consider three distinct possible stages of resource maturity and technological evolution: (1) in the early stages, where efforts are underway to find the so-call "sweet spots," which often represent a very small portion of the total area of a play; (2) in the middle stages, where resource understanding and technology progresses to improve well performance and lower costs; and (3) in the later stages of resource depletion, where higher quality "core" areas have been developed and subsequent drilling progresses to less attractive, higher cost extension areas.
- **Understanding Environmental Best Practices for Shale Resource Development.** Since any UH resource development that occurs in Europe likely will use the latest and best environmental management practices, such practices, primarily as currently pursued in the US, are explicitly assumed in the project costing, economic assessments, and associated benefits estimation. These are described in more detail later in this report.
- **Understanding the Key Stages of the Project Life Cycle Supporting UH Resource Development.** UH resource development is described in terms of specific phases and areas of activity. Each of the key stages of the project life cycle, from initial basin exploration, through well drilling, facilities construction, production operations, and site closure, is characterized. For each stage, the products, services and operations required, and the labour that would need to be employed to facilitate those supply chain activities, is described.

Prospectivity of UH Resource Plays

Published estimates of the shale oil and gas resource potential in Poland and Germany cover a considerable range, and remain highly uncertain.

In Poland, at the low end, the US Geological Survey (U.S. Geological Survey, July 2012) estimated the mean potential of the shale gas in Poland to be 38.1 million cubic meters, with a mean estimate of crude oil and natural gas liquids of 168 million barrels.[2] The National Geological Institute of Poland estimates are somewhat higher; with estimated recoverable shale gas resources in Poland ranging between 346 and 768 billion cubic meters (Bcm), with from 1.6 to 2.0 billion barrels of estimated recoverable shale oil (Polish Geological Institute, March 2012). Wood McKenzie estimates the size of the resource to be 1.4 trillion cubic meters, while Rystad Energy estimated this potential to be 1.0 trillion cubic meters (Polish oil and gas company (PGNiG, November 2014)).

In Germany, the German Federal Institute for Geosciences and Natural Resources (Bundesanstalt für Geowissenschaften und Rohstoffe, BGR) published a comprehensive study (in German) in 2016 that estimates the potential for shale gas in Germany to be 0.7 to 2.3 trillion cubic meters (BGR, 2016). This assessment builds upon previous work by Advanced Resources International for the U.S. Energy Information Administration (ARI, 2011) and (ARI, 2013), the first comprehensive geological assessment of shale oil and gas resources in Europe. This pioneering work represents the most comprehensive, and most optimistic, assessment of the **technical** potential for shale gas in Europe (this report did not assess **economic** potential).

Some national geological surveys such as the Polish Geological Institute (PGI) estimate from 2012 consider that estimates such as these from international organizations such as the U.S. EIA may be "highly inflated" (Polish Geological Institute, 2012). *However, as discussed in more detail later in this report, estimates of economic and employment benefits in this study are determined based on the assumption that they are only applicable to a small portion of the total UH resources in the two countries that ultimately gets developed (the so-called hypothetical "sweet spot" assumed to be commercially viable). Thus, different estimates of total UH resource potential would not impact these results. For example, the "sweet spot" defined for Poland discussed below represents only 0.6% of the total resource potential for Poland in the U.S. EIA assessment, or only 8% of the low end of the range of resource potential estimated by the 2012 PGI assessment. Similarly, the "sweet spot" characterized for Germany represents only 2.7% of the U.S. EIA assessment, and 3% of the low end of the range of the BGR assessment for the country.*

Nonetheless, the U.S. EIA study is unique among the various assessments in providing the necessary detail on potential geologic and reservoir properties for conducting detail assessments of technical recovery and economic potential, which are key features of this assessment. Specifically, the U.S. EIA study reviewed, assessed, and summarized preliminary geological and reservoir data for shale plays that included the depositional environment (marine vs non-marine), depth (to top and base of shale interval), structure, including major faults, gross shale interval, organically-rich gross and net shale thickness, total organic content (TOC, by weight), and thermal maturity (Ro). This led to establishing the areal extent of each major shale formation, defining the prospective area for each shale formation, estimating the risked shale hydrocarbon resource in-place, and calculating the technically recoverable hydrocarbon resources in each.

These data are summarized for both shale gas and shale oil resources for Poland and Germany in Tables 1 through 4. Original characterizations in the U.S. EIA study have been modified somewhat based on the results of more recent drilling in Poland and Germany.

[2] If this estimate turns out to be accurate, estimating potential benefits from UH resources in Poland would be unnecessary, since there will be none.

Table 1. Shale Gas Reservoir Properties and Resources of Poland

			Baltic/Warsaw Trough ($41,960 km^2$)			Lublin ($12,900 km^2$)	Podlasie ($17,090 km^2$)			Fore Sudetic ($51,020 km^2$)
Basic Data	Basin/Gross Area		Baltic/Warsaw Trough ($41,960 km^2$)			Lublin ($12,900 km^2$)	Podlasie ($17,090 km^2$)			Fore Sudetic ($51,020 km^2$)
	Shale Formation		Llandovery			Llandovery	Llandovery			Carboniferous
	Geologic Age		L. Sil - Ord. - U. Cambrian			L. Sil - Ord. - U. Cambrian	L. Sil - Ord. - U. Cambrian			Carboniferous
	Depositional Environment		Marine			Marine	Marine			Lacustrine
Physical Extent	Prospective Area (km^2)		2,150	5,360	14,710	6,190	2,590	2,850	2,230	23,490
	Thickness (m)	Organically Rich	250	250	250	127	165	165	165	101
		Net	138	138	138	70	91	91	91	55
	Depth (m)	Interval	2,000 - 3,000	2,100 - 4,000	2,700 - 4,900	2,100 - 4,900	1,800 - 2,700	2,000 - 3,500	3,000 - 4,900	2,400 - 4,900
		Average	2,500	3,050	3,810	3,350	2,290	2,900	3,810	3,660
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		3.9%	3.9%	3.9%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.80%	1.35%	0.85%	1.15%	1.80%	1.60%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas	Dry Gas
	GIP Concentration (Billion m^3/km^2)		0.40	1.43	1.98	1.00	0.30	0.90	1.34	0.73
	Risked GIP (Billion m^3)		344	3,071	11,653	1,296	186	616	715	3,020
	Risked Recoverable (Billion m^3)		34	614	2,331	259	19	123	143	604

Source: (ARI, 2013)

Table 2. Shale Oil Reservoir Properties and Resources of Poland

Basic Data	Basin/Gross Area		Baltic/Warsaw Trough ($41,960 km^2$)		Podlasie ($17,090 km^2$)	
	Shale Formation		Llandovery		Llandovery	
	Geologic Age		L. Sil - Ord. - U. Cambrian		L. Sil - Ord. - U. Cambrian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (km^2)		2,150	5,360	2,590	2,850
	Thickness (m)	Organically Rich	250	250	165	165
		Net	138	138	91	91
	Depth (m)	Interval	2,000 - 3,000	2,100 - 4,000	1,800 - 2,700	2,000 - 3,500
		Average	2,500	3,050	2,290	2,900
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		3.9%	3.9%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (Million m^3/km^2)		2.6	0.8	2.2	0.7
	Risked OIP (Million m^3)		2,230	1,690	1,380	460
	Risked Recoverable (Million m^3)		111	84	69	23

Source: (ARI, 2013)

Table 3. Shale Gas Reservoir Properties and Resources of Germany

Basic Data	Basin/Gross Area		Lower Saxony ($25,900 km^2$)			
	Shale Formation		Posidonia			Wealden
	Geologic Age		L. Jurassic			L. Cretaceous
	Depositional Environment		Marine			Lacustrine
Physical Extent	Prospective Area (km^2)		4,120	1,990	3,600	1,860
	Thickness (m)	Organically Rich	30	30	30	34
		Net	27	27	27	23
	Depth (m)	Interval	1,800 - 3,000	3,000 - 4,000	4,000 - 5,000	1,000 - 3,000
		Average	2,440	3,510	4,420	1,830
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Slightly Overpress.
	Average TOC (wt. %)		8.0%	8.0%	8.0%	4.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.00%	0.85%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas
	GIP Concentration (Billion m^3/km^2)		0.12	0.48	0.62	0.06
	Risked GIP (Billion m^3)		291	575	1,335	51
	Risked Recoverable (Billion m^3)		29	115	334	4

Source: (ARI, 2013).

Table 4. Shale Oil Reservoir Properties and Resources of Germany

Basic Data	Basin/Gross Area		Lower Saxony (25,900 km^2)		
	Shale Formation		Posidonia		Wealden
	Geologic Age		L. Jurassic		L. Cretaceous
	Depositional Environment		Marine		Lacustrine
Physical Extent	Prospective Area (km^2)		4,120	1,990	1,860
	Thickness (m)	Organically Rich	30	30	34
		Net	27	27	23
	Depth (m)	Interval	1,800 - 3,000	3,000 - 4,000	1,000 - 3,000
		Average	2,440	3,510	1,830
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Slightly Overpress.
	Average TOC (wt. %)		8.0%	8.0%	4.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%
	Clay Content		Low/Medium	Low/Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil
	OIP Concentration (Million m^3/km^2)		0.8	0.3	0.6
	Risked OIP (Million m^3)		1,450	230	510
	Risked Recoverable (Million m^3)		72	12	20

Source: (ARI, 2013).

In these assessments, explicit attention was given to the specification of resource characteristics, which will directly influence project costs and well production performance, which, other than oil and gas prices, are the largest determinants of potential economic viability, and thus lead to structure of the life cycle of projects, and their associated benefits. The characterizations of each of the two countries are provided in more detail in the paragraphs below.

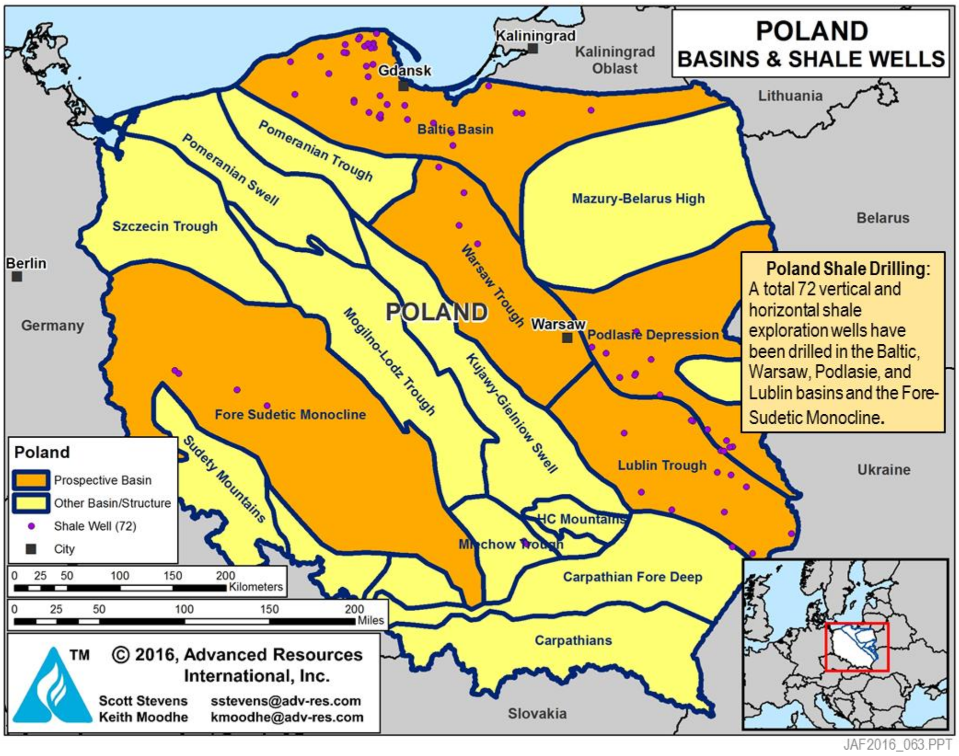
Poland Shale

During the past five years, major integrated oil and gas companies like Chevron, ConocoPhillips, ExxonMobil, Marathon, PGNiG, and TOTAL have pursued shale exploration in Poland. In total, 54 vertical and 18 horizontal wells were drilled by these various operators; of which, only 25 wells were hydraulically fractured[3]. These wells were drilled in the Baltic, Warsaw, Podlasie, and Lublin basins and the Fore-Sudetic Monocline. The results of this drilling have been disappointing. Initial production rates were low, and the reservoir conditions associated with these wells were determined to be generally unfavourable (many faults, high clay, high tectonic stress).

The location of these wells are shown in Figure 1.

[3] The Poland CBDG online well viewer service (CBDG, last access March 2016) was used to collect data on well counts. This also matches the Polish Geological Survey's exploration status report (Gaz i Ropa, 2016).

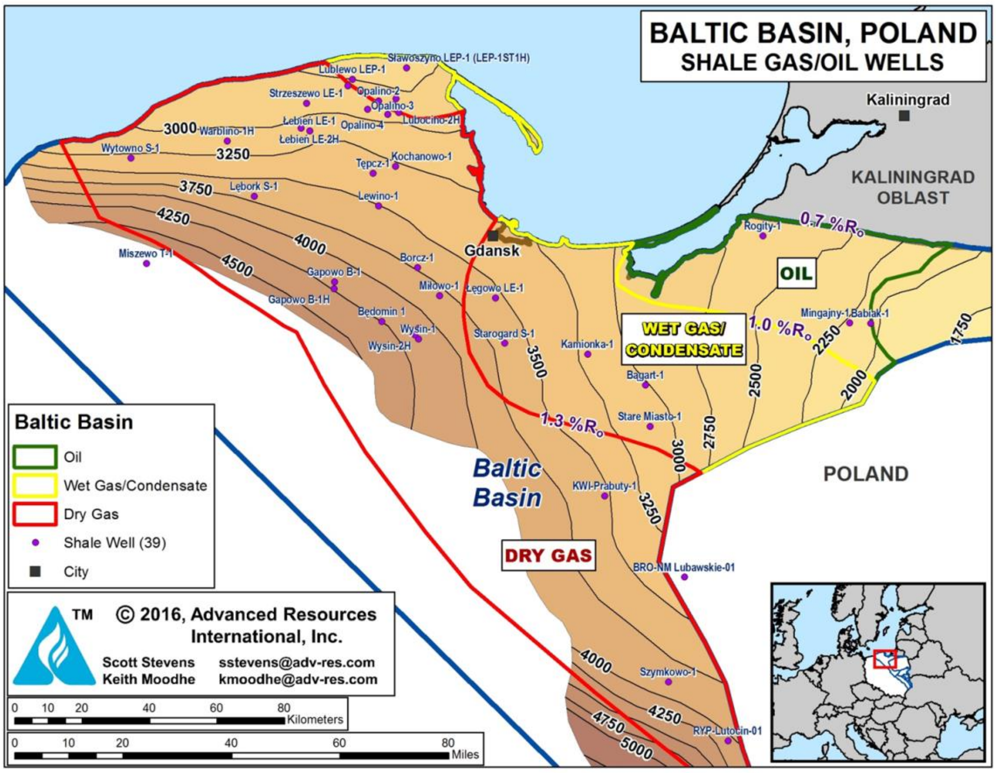
Figure 1. Major Basins and Shale Wells in Poland



Source: Advanced Resources International, 2016; modified after ARI 2013

The Baltic Basin, based on the little characterization and drilling conducted so far, appears to have the greatest commercial potential. It appears that the basin is more oil prone to the east, more gas prone in the west, with a wet gas/condensate prone area in between (Figure 2). Nonetheless, this is based on only 39 wells drilled to date.

Figure 2. Shale Gas/Oil Wells in Poland, Indicating Characteristics of Prospective Areas



Source: Advanced Resources International, 2016; modified after ARI 2013

Relatively speaking, the commercial potential of the Podlasie and Lublin basins and the Fore-Sudetic Monocline appears to be much lower, at least based on drilling to date.

Germany Shale

The Lower Saxony Basin in Germany has produced 2 billion barrels of oil and 963 billion cubic meters (Bcm) (34 trillion cubic feet (Tcf)) of gas from conventional reservoirs, corresponding to 97% of Germany's historical onshore production. However, since the benefits characterization in the report is focused on future potential, the focus here for Germany is on the potential of shale oil and gas resources.

While BNK, Dart, Realm, and San Leon had leased shale gas acreage in Germany, ExxonMobil is the only company that has actually drilled and tested any shale wells to date. Between 2008 and 2011, ExxonMobil drilled five shale test wells, all vertical except for one short side-track. Only one vertical shale well was hydraulically fractured; and no horizontal wells have been attempted in shales in Germany to date. Minimal data has been released concerning these wells, except for the following:

- Damme 2/2A (Munsterland concession; 2008): 3,330 meter (m) total depth (TD) penetrated 700 m thick Wealden (L. Cretaceous, Berriasian-Tithonian) and 30 m thick Posidonia shale (L. Jurassic, Toarcian Lias). Tested core but not fracked.
- Damme 3 (2008): located just 70 m SW of the 2 well, was shallower at 1,610 m. tested only Wealden shale. 3-stage frac was conducted in 2009 but results not disclosed.
- Luenne-1 (Bramsche concession; 2011): TD 1,575 m including 250-m lateral (1a). 550-m thick Wealden and <25-m thick Posidonia shale. Frac was planned but not carried out.

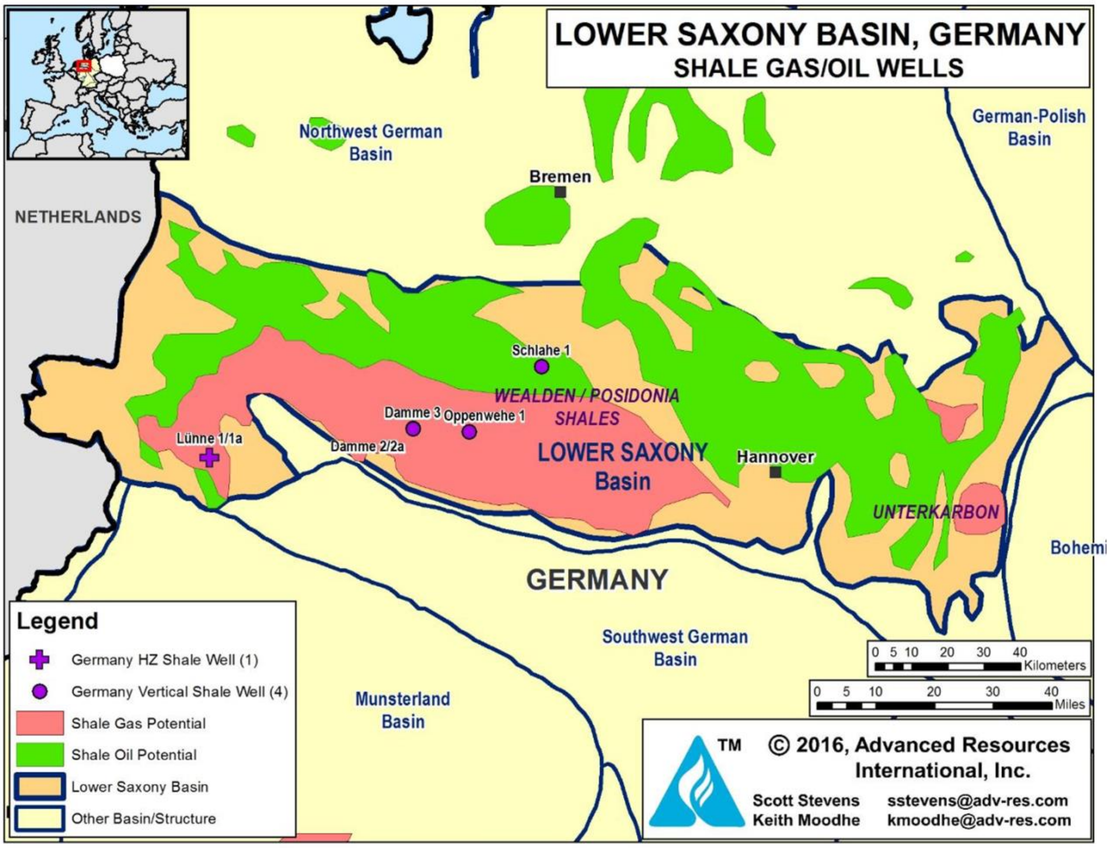
- Oppenwehe 1 (Minden concession in Rhine-Westphalian region). TD 2,660 m penetrated 600-m thick Wealdon and 35-m Posidonia shale, both organic-rich.
- Schlahe-1 (Scholen concession; 2009). TD 1,485 m penetrated 250-m thick Wealden and 35-m thick Posidonia shale; positioned beneath conventional oil sandstone reservoir of Barenburg field. July 2015: Vermillion farmed into ExxonMobil position in L. Saxony Basin but is pursuing conventional targets, not shale.

The location of these wells are shown in Figure 3. Based on this limited information, the northern portion appears to have shale in the crude oil window, while the southern portion is in the thermally more mature gas window.

In July 2015, Vermillion farmed into ExxonMobil position in the Lower Saxony Basin, but is pursuing conventional targets, not shale.

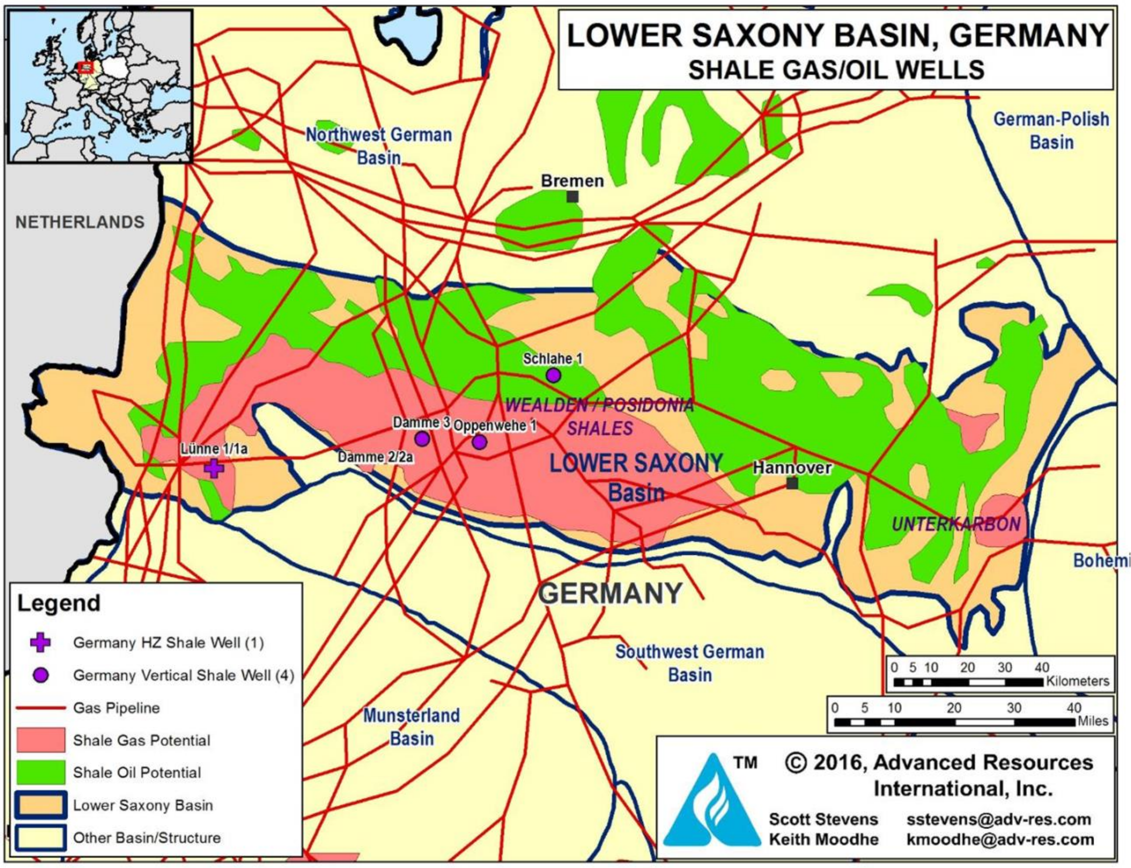
However, should commercial volumes of shale gas resources be discovered in Germany, and their development is allowed to take place, a good natural gas pipeline network already exists to tap into, Figure 4.

Figure 3. Major Basins and Shale Wells in Germany



Source: Advanced Resources International, 2016; modified after ARI 2013

Figure 4. Overlay of the Gas Pipeline Network in Germany



Source: Advanced Resources International, 2016; modified after ARI 2013

Prospectivity of Other UH Resource Plays

In addition to shale gas and shale oil, other UH resources – specifically low permeability ("tight") gas and coalbed methane (CBM) also exist in Poland and Germany. Like that for shale resources, published estimates of the resource potential of these other UH resources also cover a considerable range. However, since these resources have been pursued somewhat longer that shale resources, their estimation is perhaps less uncertain.

In Poland, the Polish Geological Survey (PGS) estimates that from 1,529 to 1,995 Bcm of tight gas resources in place exist in Poland, with 153 to 200 Bcm estimated to be recoverable. Technically recoverable CBM resources are estimated to be on the order of 270 Bcm (Polish Geological Institute, 2003).

A recent study by the EU-JRC estimated that technically recoverable CBM resources in Poland were 1,363 Bcm, and were 394 Bcm in Germany (Schultz & Alder, 2016).

Finally, a report commissioned by the IEA Greenhouse Gas R&D Programme (U.S. IEA, 2013/10) estimated that technically recoverable CBM resources in Poland were 142 Bcm, and were 453 Bcm in Germany.

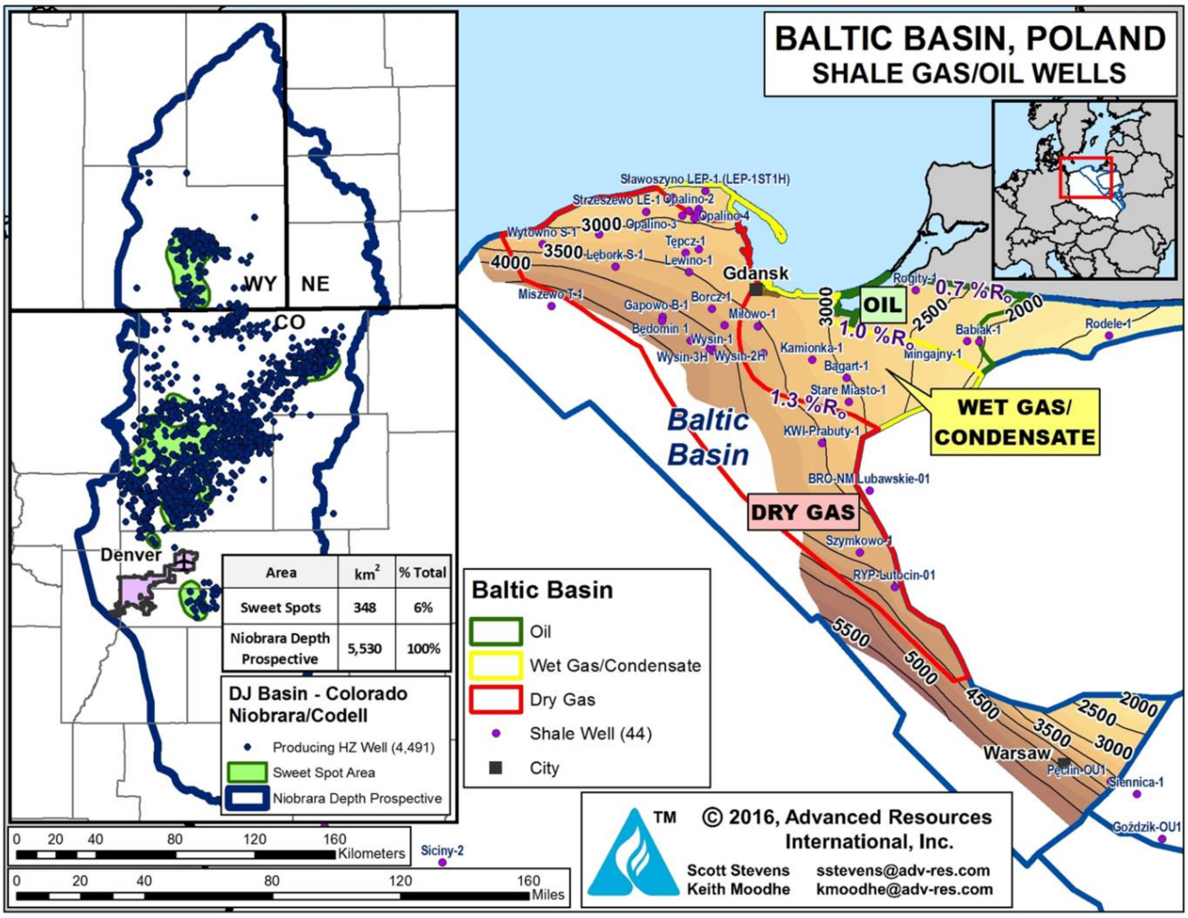
In the remainder of this study, while the attention focuses on new shale resource development, and the potential associated benefits that could result, comparable benefits could also be realizable if other new UH resources are developed at the same pace and scale as that assumed for shale oil and gas resources, assuming such resources are economically viable to pursue. As described in more detail later in this report, in general, cost estimates for shale oil and gas development and production should be applicable for other UH resources like low permeability (tight) gas sands and coal bed methane (CBM) resources. In fact, for tight gas, they should be directly applicable. For CBM, well depths would generally be shallower, so drilling costs would probably need to be adjusted to account for the shallower depths. Moreover, CBM wells do not need to be as extensively hydraulically fractured as shale wells, so those costs are likely to be somewhat slower. On the other hand, large volumes of water are usually produced in the initial stages of CBM development and production, adding to cost relative to shale gas wells.

Nature of Exploration in Europe Relative to USA – The Role of Resource Maturity

The major integrated companies (Chevron, ConocoPhillips, ExxonMobil, Marathon, PGNiG, TOTAL) that have pursued shale exploration in Poland and Germany are not the traditional types of companies that initially successfully pursued shale plays in North America. In contrast, the North American plays were initially pursued by independent, non-integrated oil and gas exploration and production (E&P) companies such as Chesapeake, Devon, Pioneer, Range, and Southwestern. Such companies are characterized by a combination of strong technical capability and an entrepreneurial, low-cost, and generally more patient approach. This experienced and successful class of company has not attempted much shale exploration in Europe.

Moreover, the North America experience suggests that shale exploration drilling to date in Europe has not been sufficient to locate potential geologic "sweet spots" and optimize well drilling and completion design. For example, in the Niobrara Shale play in the Denver-Julesburg (DJ) Basin in the US (comparable in size and thermal maturity to Baltic Basin, but geologically simpler), over 200 horizontal wells (10 times the number drilled to date in Poland) were required to locate and optimize well design before large-scale commercial production commenced in 2012. Moreover, this experience identified a "sweet spot" of commercial prospectivity covering only 6% of the total basin area, represented by the green area in the left hand side of Figure 5.

Figure 5. Comparison of the Niobrara and Baltic Basin Shale Plays



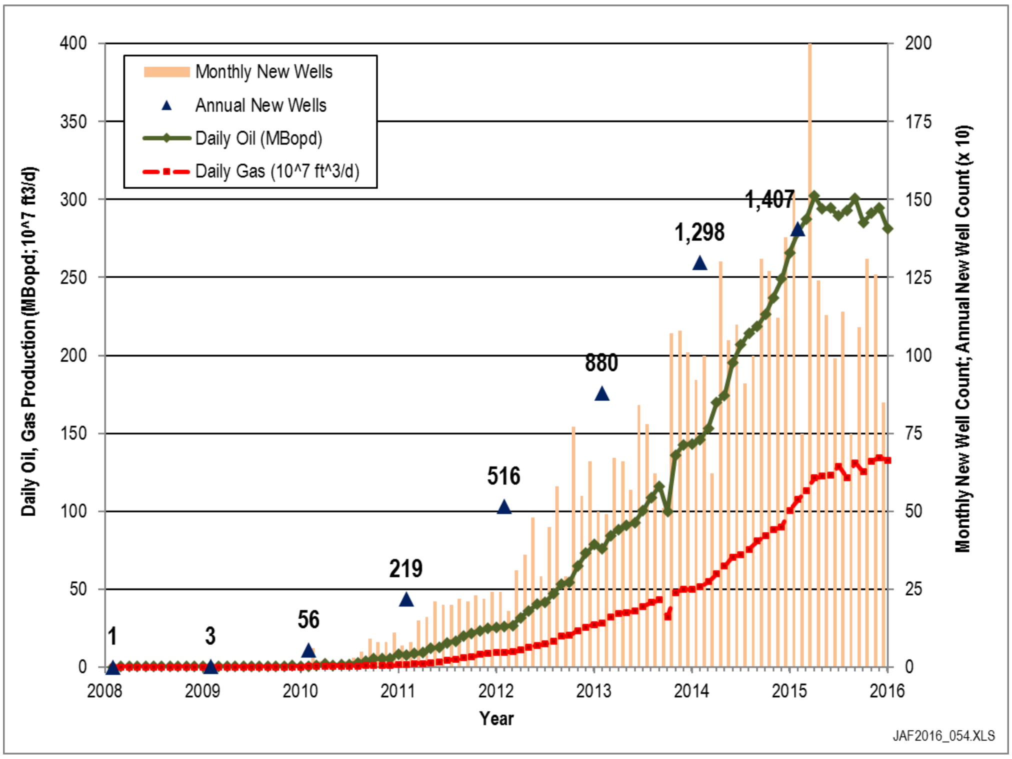
Source: Advanced Resources International, 2016; modified after ARI 2013

The history of development of this play is instructive:

- From 1980 to 2007: Sporadic attempts to produce were unsuccessful but generated much scientific understanding.
- From 2008 to 2011: 279 horizontal wells across the play established sweet spot location and drilling and completion design.

This experience is shown in Figure 6. Today, this medium-sized successful shale play is producing 45 million cubic meters (Mcm) per day (1.3 billion cubic feet per day (Bcfd)) of natural gas and 280,000 barrels per day of liquids from over 4,000 horizontally drilled, fractured wells.

Figure 6. Drilling Experience in Niobrara Shale in the DJ Basin



Source: own elaboration, based on well drilling data (Drillinginfo.com, 2016)

From this, it can be concluded that in Germany and Poland, shale exploration efforts to date has been too limited to definitively determine the potential commercial prospectivity of the various undeveloped UH plays in each country. Thus, there remains a chance that UH exploration still might succeed in these two countries, if additional exploration were undertaken to locate "sweet spots," optimize well design, and drive down costs.

Potential Impact of Technology Progress and Drilling Experience

Perhaps in contrast to some coverage in the press, the so-called "shale boom" in North America has not been an "overnight sensation." Natural gas production from shallow, fractured shale formations in the Appalachian and Michigan basins of the US has been underway for decades. While marginally economic, production was steady but relatively modest. What "changed the game" was the recognition that one could "create a permeable reservoir" and resulting high rates of production by using intensively stimulated horizontal wells. *Not many of the wells drilled to date in Europe have been horizontal wells, and most have not been intensively stimulated, or hydraulically fractured.*

Thus, this "overnight sensation" has been over 30 years in the making, building upon significant research investments in UH and shale gas technologies since the late 1970s. The key technologies of horizontal wells and intensive hydraulic stimulation were developed with significant public and private research investment and field testing, first in the Rocky Mountain tight gas formations, and next in the shallow Appalachian and Michigan Basin shales. Mitchell Energy extended this foundation of knowledge and technology, with support and participation by the Gas Research Institute (GRI), drilling the Stella Young #1 research well into the deep Barnett Shale, confirming that increased reservoir contact could make deep, low permeability shales economically viable (Gas Technology Institute, 2013).

In sum, a variety of publicly and privately funded research activities; along with government policies, incentives and transfers of technology, supported pursuit of shale and other unconventional resources in the US.

Thus, at the heart of the debate about the future outlook for UH resources in Europe, consistent with that which has taken place in North America, are three competing forces:

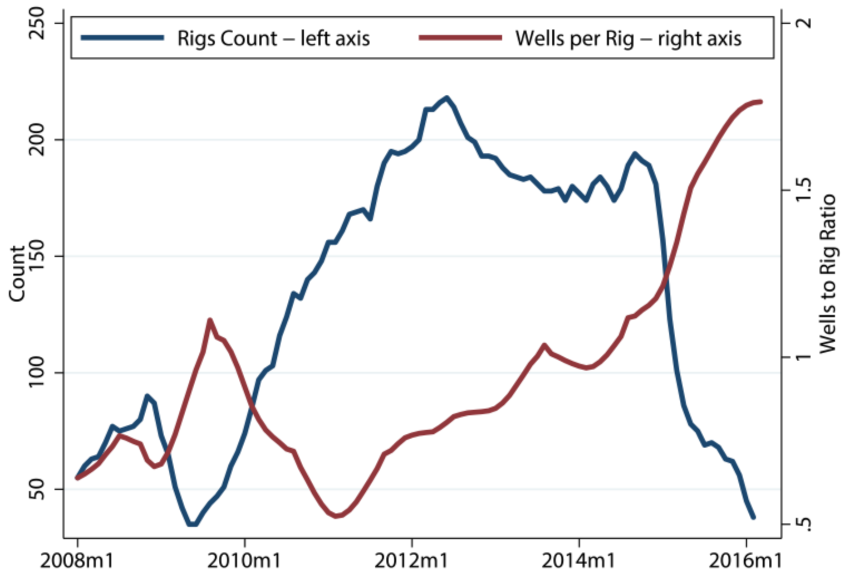
- The first force is the pace and ability to find the most productive areas of a play – the so-call "sweet spots," which often represent a very small portion of the total area of a play.
- The second force is nature's inevitable resource depletion, moving from the development of the higher quality "core" areas ("sweet spots") to subsequent drilling in less attractive, higher cost extension areas and economically marginal plays.
- The third, offsetting force is technology progress, the continuing ability of industry and its geologic/engineering talent to increase understanding of the resource, improve well performance, lower costs, and, possibly, find new "sweet spots."

Supporting this, the lower oil and gas prices experienced by the oil and gas industry for the last few years have also contributed to overall efficiency improvements that could assist shale development in Europe.

A few examples are illustrative of the impact of these forces.

As reported in (Decker, Flaaen, & Tito, 2016), improvements in the number of wells a rig can drill each month, and in the average length of each well, have contributed to the productivity gains in drilling. As shown in Figure 7, which plots data for the Bakken region in the US, the number of wells drilled per rig in a given month has risen steadily since 2011, and it accelerated further after the rig count began falling in 2014. The main driver of this greater rig efficiency is the adoption of pad drilling technology, whereby a rig can drill multiple wells from a single well pad without the need for expensive and time-consuming disassembly, relocation, and reassembly. Additionally, each well has become much longer, as the average well length has doubled.

Figure 7. Rig Counts and Wells per Rig, Bakken Region



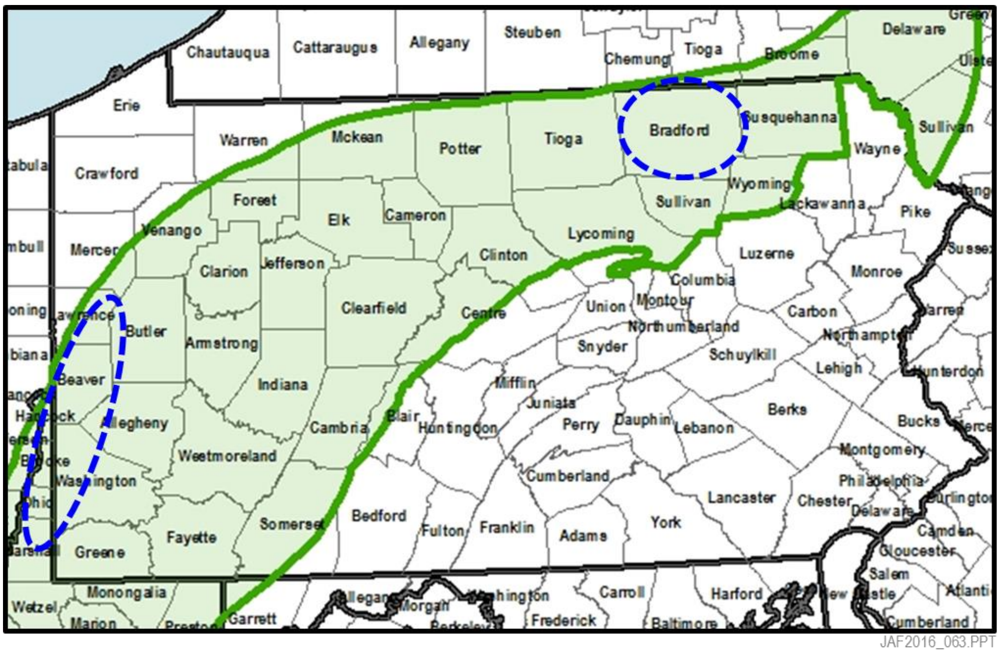
Source: (U.S. EIA, 2016)

Increased and more efficient use of water, sand, and other proppants in the fracking process has further enhanced well productivity, particularly early in the well life cycle. As a result, in addition to the increase in the number of new wells drilled per rig, production from these new wells in their first month has roughly tripled since early 2008.

In addition to substantially improving the commercial viability of these wells, these improvements have also resulted in reduced environmental impacts.

As another example, in the Marcellus shale play in the Appalachian Basin in the Eastern US, the application of improved technology to two areas – the Northeast Pennsylvania Northeast (NE PA) "Core" (Bradford County) and Southwest Pennsylvania (SW PA) Liquids Rich area (Figure 8) have led to significant improvements in well performance.

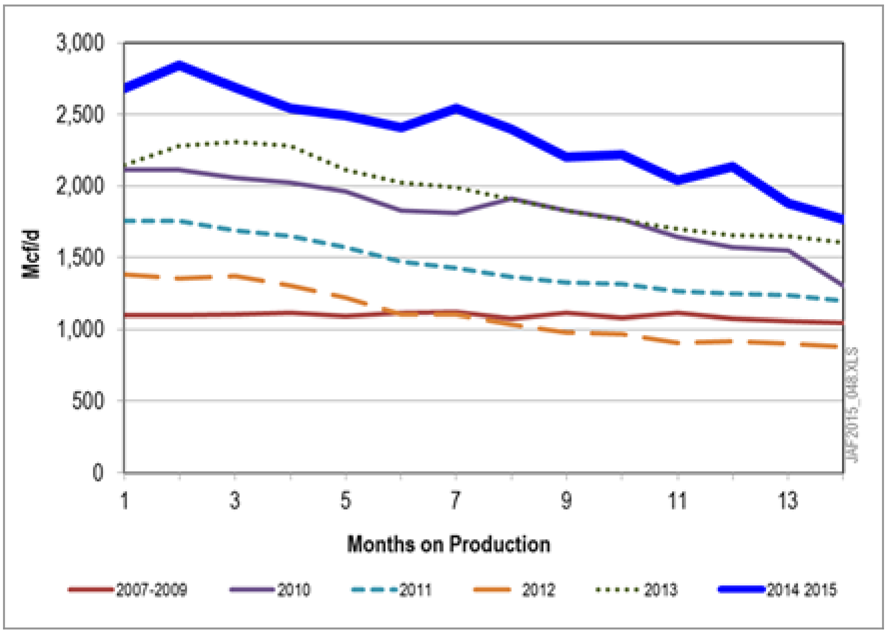
Figure 8. Areas of Major Improvements in Well Productivity (Marcellus Shale)



Source: elaboration by Advanced Resources International

In the SW PA Liquids Rich Area, well performance, while erratic during the initial years, has nearly doubled recently (Figure 9).

Figure 9. Improvements in Well Productivity
Marcellus Shale - SW PA Liquids Rich Area

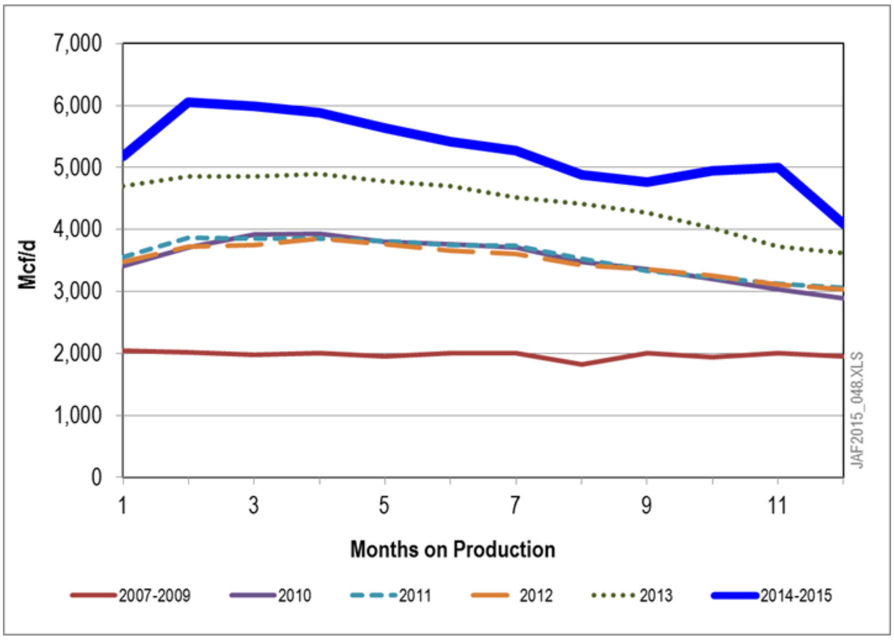


Source: elaborations by Advanced Resources International

Similarly, in Bradford County, well performance that remained relatively flat from 2007 through 2012 improved vastly in the subsequent two years (Figure 10).

Past improvements in Marcellus well productivities were primarily due to longer horizontal wells (laterals). Recent increases in well productivity are due to more intensive stimulations (more sand).

Figure 10. Improvements in Well Productivity
Marcellus Shale – Bradford County



Source: elaborations by Advanced Resources International

Perhaps no shale oil play has seen a more dramatic increase in well productivity than the "Karnes Trough" (Eastern Eagle Ford Shale Light Oil Play), a relatively mature play, with 2,430 horizontal wells drilled as of the end of 2014. Most notable are the gains achieved by EOG, the play's dominant operator, with nearly four-fold improvements in oil and gas production per well. EOG's and other operators' well locations in the "Karnes Trough" are similar (Table 5. Improvements in Well Performance: The "Karnes Trough" (Eagle Ford Shale) Case Study

Company	2012/2013 Hz Wells			2014 Hz Wells		
	IP	EUR		IP	EUR	
	(B/D)	(MBbls)	(MMcf)	(B/D)	(MBbls)	(MMcf)
EOG	1,480	290	450	2,300	1,030	1,660
Other Operators	770	360	640	800	630	750

).

Table 5. Improvements in Well Performance:
The "Karnes Trough" (Eagle Ford Shale) Case Study

Company	2012/2013 Hz Wells			2014 Hz Wells		
	IP	EUR		IP	EUR	
	(B/D)	(MBbls)	(MMcf)	(B/D)	(MBbls)	(MMcf)
EOG	1,480	290	450	2,300	1,030	1,660
Other Operators	770	360	640	800	630	750

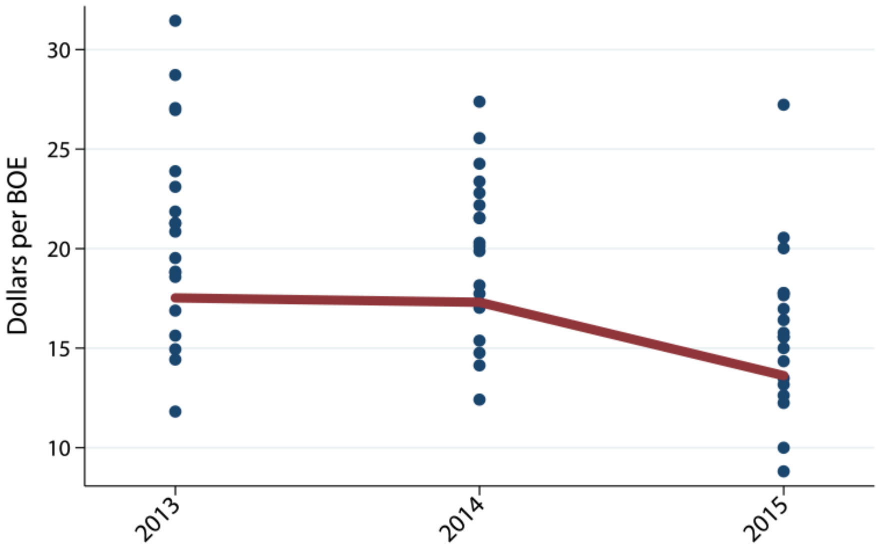
Source: elaborations by Advanced Resources International

The productivity gains contribute to, and are supplemental to, other efforts focused on reducing costs. In recent years, US companies have made extensive efforts to reduce drilling and production costs. Publicly traded oil companies report cash costs to the US Securities and Exchange Commission (SEC) in quarterly and annual filings[4]. (Decker, Flaaen, & Tito, 2016) collected these costs from 10K reports for 2013 and 2014, and also obtained the costs for the first nine months of 2015 from 10Q reports. Using data for about 25 companies with large operations in the three main shale regions focusing primarily on oil production, the results are summarized in Figure 11. Each blue dot represents a firm, and the red line shows the production-weighted average across companies. As shown, cash costs vary widely across companies; various sources also indicate wide cost dispersion across wells within firms. Nonetheless, these cash costs are declining, as oil prices have declined.

In the longer term, an important cost threshold is the long-cycle break even cost. This threshold includes drilling and transportation costs (as well as internal cost of capital hurdle rates) and therefore reflects the price at which new wells are economically profitable. Estimates of long-cycle breakeven costs also vary widely.

[4] For more information, please consult (U.S Security and Exchange Commission (SEC), 2016) https://www.sec.gov/

Figure 11. Reported Cash Costs for U.S. Exploration and Production

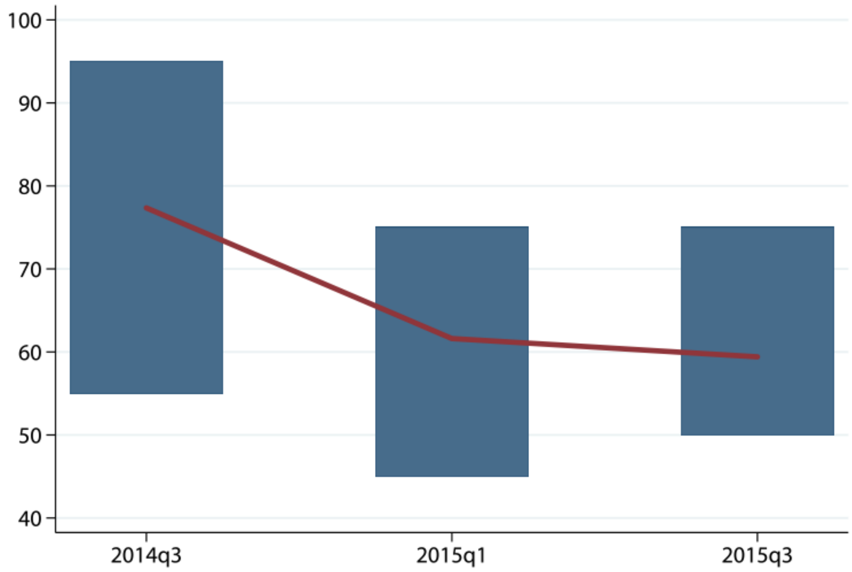


Source: (U.S Security and Exchange Commission (SEC), 2016) filings and investor reports. 2015 results only reported through Q3. Weights based on barrels of oil produced. Includes the sum of operating costs, G&A expenses, and production taxes (excludes interest)

In Figure 12, (Decker, Flaaen, & Tito, 2016) report results from quarterly surveys of oil companies administered by the Federal Reserve Bank of Kansas City (and, as such, include operations primarily in the Niobrara region). As in Figure 11, the red line represents the average across firms. Again, there exists wide variation in costs across companies. But, as with cash costs, dispersion has narrowed some, and average costs have fallen significantly since 2014. Given the pace of cost reduction, by early 2016, costs are likely to have declined further. Other shale plays in the US are exhibiting similar trends.

However, in some plays, the impact of technology improvements and cost reductions are not keeping pace with the inevitable fact of resource depletion. The Barnett Shale provided the foundation for the "shale gas revolution," showing that economically viable natural gas could be produced from deep, very low permeability formations. Natural gas production climbed rapidly, reaching 28 Mcm per day (1 Bcfd) in 2004 and 162 Mcm per day (5.7 Bcfd) in 2012. However, now, with the heart of the "core" area fully drilled, natural gas production has declined to below 113 Mcm per day (4 Bcfd), with few well permits now issued. Thus, in this case, improvements in technology are no longer able to counter resource depletion for this maturing shale gas play.

Figure 12. Long-Cycle Breakeven Estimates; Niobrara Shale



Note: Blue bars represent the distribution of breakeven prices in a given quarter.
Source: Federal Reserve Bank of Kansas City firm survey, profitable price for drilling (Decker, Flaaen, & Tito, 2016)

Similarly, the Fayetteville Shale showed that the Barnett Shale results were not a "one-off" phenomena and sparked the shale leasing "land rush." Initially, longer lateral horizontal wells led to higher productivity wells. Today, with the "core area" mature, new natural gas wells are being drilled in extension areas and production is in decline.

Nonetheless, the acquisition of data and accumulation of understanding and experience with UH resources are still early in the process in many areas in North America. And this is even more the case in Europe. Key areas include establishing the "core areas" or "sweet spots" with exploration and development drilling, improving the recovery efficiency of UH resources as knowledge and experience is gained; and sustainably developing these resources to stakeholder satisfaction – minimizing emissions and environmental and social impacts.

Thus, in this study, potential resource productivity and commercial viability is considered at up to three stages:

- In the early stages, where efforts are underway to find the so-call "sweet spots," which often represent a small portion of the total area of a play.
- In the middle stages, where resource understanding and technology progresses to improve well performance and lower costs.
- In the later stages of resource depletion, where higher quality "core" areas have been developed and subsequent drilling progresses to less attractive, higher cost extension areas.

Potential Unconventional Oil and Gas Productivity in Poland and Germany

Based on Advanced Resources' work for the U.S. EIA, specific data on each of the new shale resource plays in Poland and Germany were collected and analysed. These characteristics could be disaggregated within plays to be able to determine the relative potential economic viability of specific areas within each, and characterize potential "sweet spots" within each play. This is comparable to the ten tiers that (Gülen, Browning, & Ikonnikova, 2013) used to assess well economics in the Barnett shale, with the difference being that they based their tiers on historical well performance data, while well performance in this assessment is based on play-specific geological characteristics and geologically analogous plays. *However, while characteristics of "sweet spots" could be developed, their exact location cannot, given the low relative levels of drilling in these plays to date.*

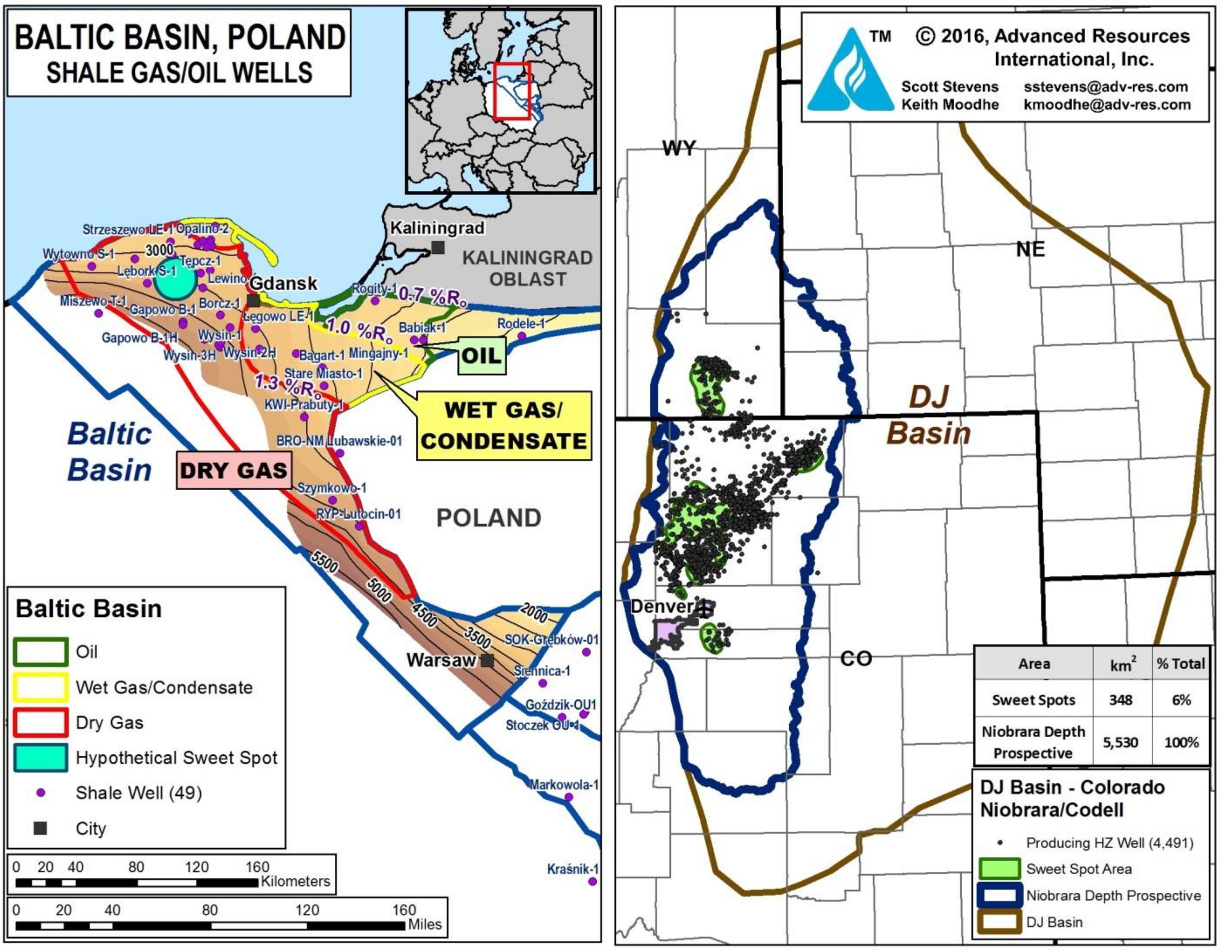
The following logic was used to generate initial, hypothetical production curves for a *yet-to-be-discovered* "sweet spot" in Poland's North Baltic Basin.

- A potential future "sweet spot" with modest productivity was posited to result from future additional exploration drilling. (Recall that the Niobrara took more wells to discover than have been drilled so far in Poland.) (See Figure 13). As noted above, the "sweet spot" defined for Poland represents only 0.6% of the total resource potential for Poland in the U.S. EIA assessment, or only 8% of the low end of the range of resource potential estimated by the 2012 PGI assessment. Similarly, the "sweet spot" characterized for Germany represents only 2.7% of the U.S. EIA assessment, and 3% of the low end of the range of the BGR assessment for the country.
- The porosity, recovery factor, and well spacing assumptions used in the U.S. EIA study were reduced somewhat to develop estimated ultimate recovery (EURs) values for fractured horizontal wells about 3,000 meters in depth below surface in the dry gas window (Table 6). A comparable EUR was developed assuming the resource falls within the oil/wet gas/condensate window.

This resulted in a Base Case estimate of a modest EUR of 14.4 million cubic meters per well (Mcm/well) (0.5 billion cubic feet (Bcf))/well EUR and 27 billion cubic meters (Bcm)) (1 Tcf) total recovery for the basin.

The assumed North Baltic Basin production curve was based on the production characteristics in the Haynesville play in the US, which is characterized by a relatively steep decline. Given the reservoir characteristics of this basin, the gentle decline more characteristic of the Marcellus shale in the US is probably not likely.

Figure 13. Representation of a Potential "Sweet Spot" (Green Circle) in Poland's North Baltic Basin, Compared to that in the Niobrara



Source: elaborations by Advanced Resources International; modified after ARI 2013

Table 6. Revised Resource Characteristics of a Potential "Sweet Spot" in Poland's North Baltic Basin

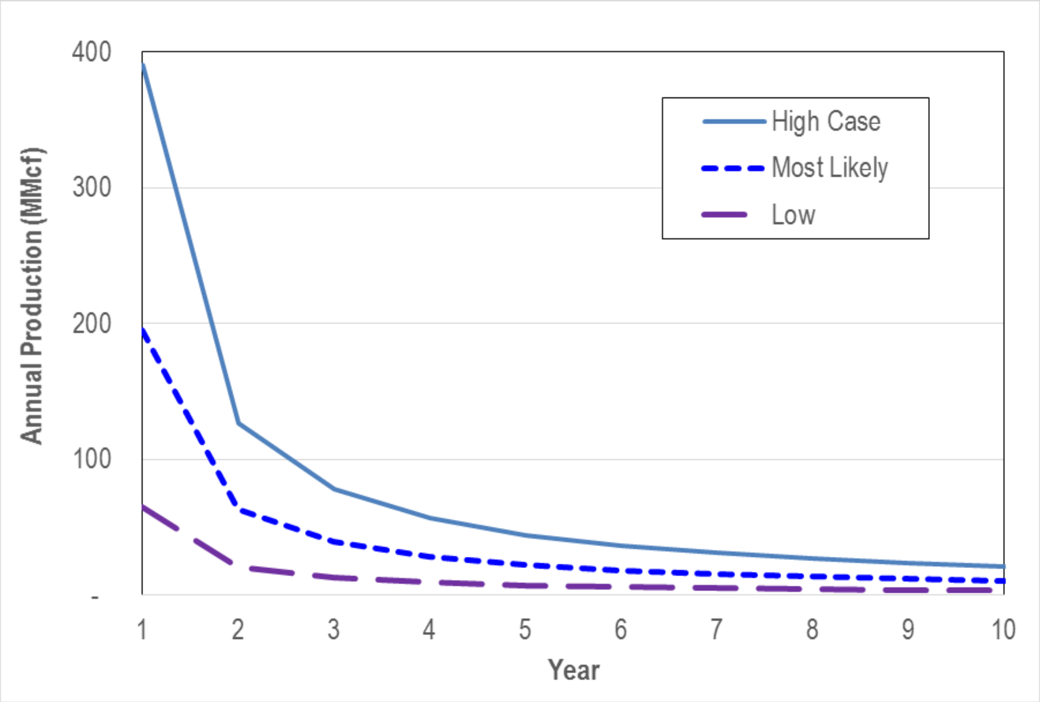
			Assumes Sweet Spot Discovery		
			Scenario 1	Scenario 2	Scenario 3
			Most Likely	Low	High
Basic Data	Basin/Gross Area		Baltic Basin		
	Shale Formation		Llandovery		
	Geologic Age		L. Sil - Ord. - U. Cambrian		
	Depositional Environment		Marine		
Physical Extent	Prospective Area (km^2)		610		
	Thickness (m)	Organically Rich	122		
		Net	61		
	Depth (m)	Interval	3,200 - 3,800		
		Average	3,500		
Reservoir Properties	Reservoir Pressure		Mod. Overpress.		
	Average TOC (wt. %)		2.0%		
	Thermal Maturity (% Ro)		1.60%		
	Clay Content		High		
Devt. Assump.	Recovery Efficiency		15%	5%	30%
	Well Spacing (km^2)		0.16		
Resource	Gas Phase		Dry Gas		
	GIP Conc. (Million m^3/km^2)		591		
	Risked GIP (Billion m^3)		180		
	Risked Recoverable (Billion m^3)		27.0	9.0	54.1
Per-Well EUR	Gas (Billion ft^3)		0.5	0.2	1.0
	Gas (Million m^3)		14.4	4.8	28.7
	No. of Gas Wells Required		1,884	1,884	1,884

Resource	Phase	Oil/Condensate		
	Risked OOIP (million barrels)	1,097		
	Risked Recoverable (million barrels	164.5	54.8	329.1
Per-Well EUR	Oil (barrels)	87,322	29,107	174,645

Source: elaborations by Advanced Resources International; modified after ARI, 2013.

The initial productivity (IP) of around 3 million cubic feet per day (MMcfd) is higher than the best well in Poland discovered so far, which had an IP at 0.5 MMcfd. Low and High cases were also defined. These are shown in Figure 14 for the first ten years of production.

Figure 14. Representation of Three Potential Gas Production Curves for the First 10 Years of Production for Poland's North Baltic Basin



Source: own elaborations on modeling results

The three cases for gas are summarized as follows:

- Base Case (most likely): EUR/well – 14.4 Mcm; total resource – 27 Bcm
- High Case: EUR/well – 28.7 Mcm; total resource – 54 Bcm
- Low Case: EUR/well – 4.8 Mcm; total resource – 9 Bcm.

Likewise, the three cases assuming oil/liquids are summarized as follows:

- Base Case (most likely): EUR/well – 87,322 barrels; total resource – 164.5 million barrels
- High Case: EUR/well – 174,645 barrels; total resource – 329.1 million barrels
- Low Case: EUR/well – 29,107 barrels; total resource – 54.8 million barrels.

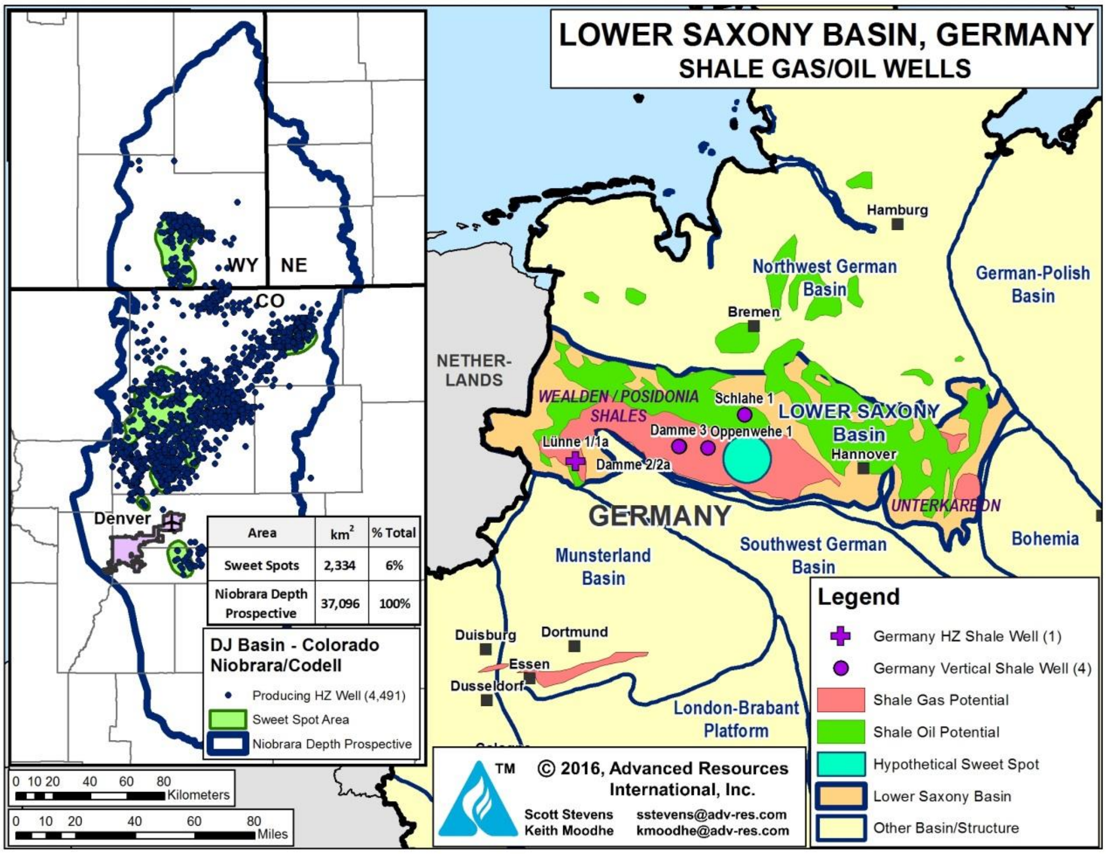
Developing these resources in the core "sweet spot" area of 610 km^2 would require an estimated 1,800 to 1,900 wells.

Similarly, for Germany, the following logic was used to generate hypothetical production curves for a yet-to-be-discovered "sweet spot" in the Lower Saxony Basin:

- A circular Lower Jurassic Posidonia shale, according to nearby Exxon wells. Gross thickness was assumed to be 35 meters, with a net thickness of 28 meters (used 80%) (Table 7)
- Geologic studies seem to indicate good TOC throughout most of the formation.
- The same Haynesville decline curve shape for EUR was used, as the Posidonia is also dry gas and near age-equivalent.

- The Most Likely/Base Case scenario was reduced somewhat since no results have been reported that show gas has/can be produced from the shales.

Figure 15. Representation of a Potential "Sweet Spot" (Green Circle) in Germany's Lower Jurassic Posidonia shale, Compared to that in the Niobrara



Source: elaborations by Advanced Resources International; modified after ARI 2013

Table 7.Revised Resource Characteristics of a Potential "Sweet Spot" in Germany's Lower Jurassic Posidonia Shale

			Assumes Sweet Spot Discovery		
			Scenario 1	Scenario 2	Scenario 3
			Most Likely	Low	High
Basic Data	Basin		Lower Saxony Basin		
	Shale Formation		Posidonia		
	Geologic Age		L. Jurassic		
	Depositional Environment		Marine		
Physical Extent	Prospective Area (km^2)		518		
	Thickness (m)	Organically Rich	35		
		Net	28		
	Depth (m)	Interval	2,000 - 3,000		
		Average	2,500		
Reservoir Properties	Reservoir Pressure		Normal		
	Average TOC (wt. %)		8.0%		
	Thermal Maturity (% Ro)		2.0%		
	Clay Content		Medium		
Devt. Assump.	Recovery Efficiency		15%	5%	30%
	Well Spacing (km^2)		0.16		
Resource	Gas Phase		Dry Gas		
	GIP Conc. (Million m^3/km^2)		521		
	Risked GIP (Billion m^3)		54		
	Risked Recoverable (Billion m^3)		8.1	2.7	16.2
Per-Well EUR	Gas (Million m^3)		12.7	4.2	25.3
	No. of Wells Required		640	640	640

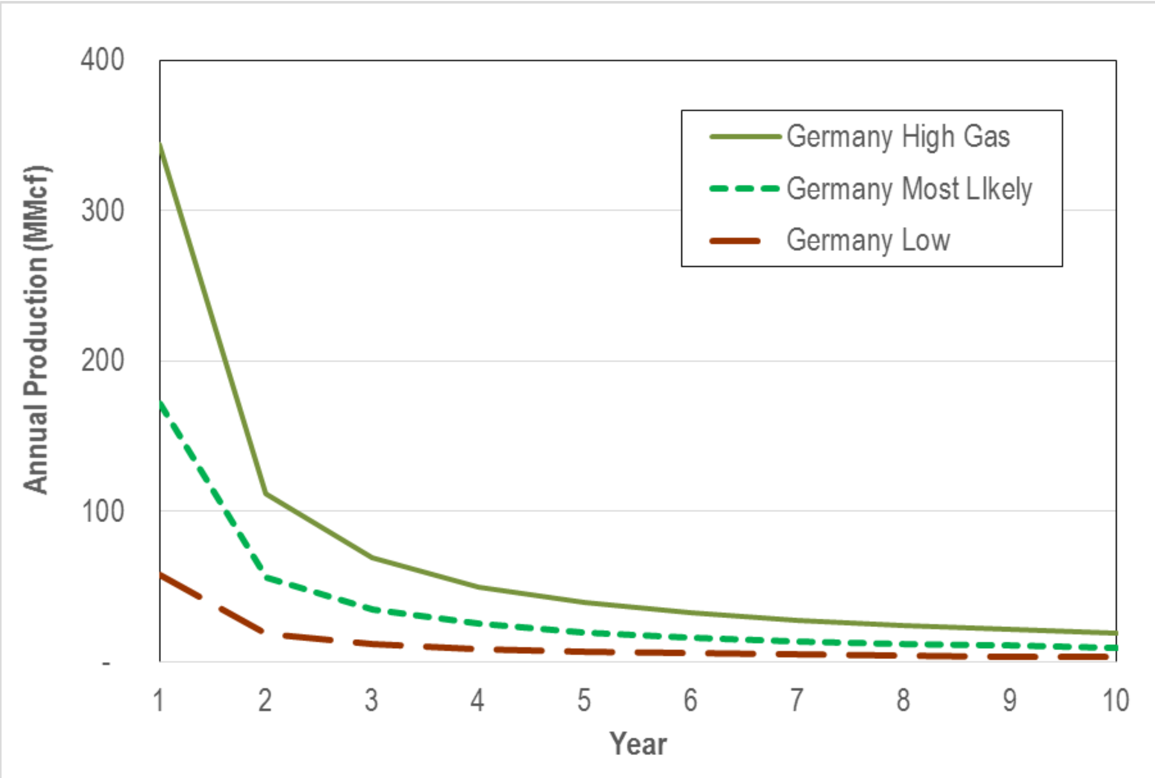
Source: elaborations by Advanced Resources International; modified after the ARI, 2013.

Thus, the three cases for gas in Germany are summarized as follows:

- Base Case (most likely): EUR/well – 12.7 Mcm; total resource – 8.1 Bcm
- High Case: EUR/well – 25.3 Mcm; total resource – 16.2 Bcm
- Low Case: EUR/well – 4.2 Mcm; total resource – 2.7 Bcm.

Developing these resources in the core "sweet spot" area of 518 km^2 would require an estimated 640 wells. The first ten years of the assumed production curves corresponding to these cases are shown in Figure 16.

Figure 16. Representation of Three Potential Gas Production Curves for the First 10 Years of Production for Germany's Lower Jurassic Posidonia Shale



Source: own elaborations on modelling results

Project/Prospect-Specific Costs

The cost model used in this study for assessing future UH resource development in Europe is based on unpublished and proprietary work for U.S. EIA to develop a component-based cost model for use by U.S. EIA to assess the commercial viability of shale gas development in various areas around the world. The following steps were pursued to develop the cost estimates assumed in the model:

- Detailed, component-specific capital cost data were assembled for well drilling and completion, fracture stimulation, surface equipment, gas gathering, gas treating, and compression.
- Detailed, component-specific cost data were assembled for well operations, with special attention given to key environmental costs, such as water treatment and disposal and site maintenance.
- The component costs for each of the cost categories were characterized to enable accurate representation of the linkages between the cost of steel, fuel, and labour for each area.
- The component costs for each were also assessed to establish relationships between cost and well depth, geographic areas, and special environmental settings.
- Costs are adjusted based on regional-cost adjustment factors appropriate for operating in different regions of the world.

It is important to note that these costs represent a case characteristic of the middle to later stages of resource development maturity in a play, where resource understanding and technology progress has made substantial strides to improve well performance and reduce costs. In the early stages of development in a play, where efforts are underway to find the so-call "sweet spots," where resource understanding, well drilling practices, and development efficiencies are still a challenge, costs are likely to be considerably higher than this, perhaps on the order of two to three times higher. In fact, if such costs remain at this higher level, economic viability of even the "sweet spot" will likely not be realizable.

Drilling, Completion and Stimulation Costs

To develop estimates for drilling and completion costs, including stimulation costs, line items costs from the company-specific Authorizations for Expenditure (AFEs) obtained for this efforts were grouped into four cost types: "steel", "labour", "other drilling and completion", and "hybrid". Hybrid line items were deemed to include some portion of both labour and other drilling and completion costs as a part of the total line item cost (i.e. "Casing Crews & Services" includes costs for both the casing equipment, as well as the casing crew labour). Each line item was assigned a subcategory, representing common cost items incurred in drilling horizontal shale wells.

Labour requirements developed to correspond to various development activities (described later in the report) were cross-checked for consistency against costs designated as "labour costs," and corresponded well.

Table 8 summarizes well drilling and completion costs, fracturing costs, steel costs, and labour costs for a representative example US well at a depth of 3,050 meters (10,000 feet). Based on the available data, cost per fracturing stage relationships were developed for fracturing materials, perforation materials, and fracturing water usage. This includes summaries for the steel costs associated with such a well, as well as the associated labour costs.

These costs are assumed to be equally applicable to oil and gas wells.

This model estimates vertical and horizontal shale well drilling costs, completion and stimulation costs; lease equipment costs, gas gathering and compression costs, and well operating costs. Costs are estimated as a function of vertical well depth, lateral length, steel costs, labour costs, fuel costs, and variations in regional construction costs.

Lease Equipment Costs

Lease equipment costs are developed based on data collected and reported by (U.S. EIA, 2010). Cost estimates are reported as a function of US region, well depth, and, in the case of gas, average production rate. For purposes of this report, average US costs were assumed. The assumed lease equipment costs for oil wells are shown in Table 9, and for gas wells in

Table 10.

Annual Operating Costs

Annual shale well operating costs are also derived from the Oil and Gas Lease Equipment and Operating Costs reports (U.S. EIA, 2010). Reported operating cost data were assembled for wells varying by depth and production, which produced a linear cost curve. The overall annual operating cost is further divided into labour and non-labour costs. Labour costs are assumed to be 80% of the total operating cost, while non-labour costs are assumed to be 20% of the total operating cost.

Annual operation costs (in 2010 dollars) for oil wells are shown in Table 11, and for gas wells in

Table 12.

Table 8. Summary of Drilling and Completion (D&C) Costs for a 3,050 Meter Shale Well[5]

	EURO	USD
Estimated Drilling and Completion Costs		
Drilling/Completion	€ 1,506,284	$1,673,649
Misc/Rentals	€ 501,027	$556,697
TOTAL D&C COSTS	**€ 2,007,311**	**$2,230,346**
Materials/Overhead		
Cement	€ 88,460	$98,289
Chemicals/Fluids	€ 324,821	$360,912
Water	€ 24,566	$27,295
Fuel	€ 186,340	$207,044
Environmental/Safety	€ 25,795	$28,661
Water Pit/Location	€ 136,565	$151,739
Overhead/Permits	€ 135,468	$150,520
TOTAL MATERIALS/OVERHEAD COSTS	**€ 922,014**	**$1,024,460**
Fracturing Costs		
Fracturing	€ 1,261,882	$1,402,091
Perforation	€ 135,686	$150,762
Frac Water	€ 346,000	$384,444
TOTAL FRACTURING COSTS	**€ 1,743,567**	**$1,937,297**
TOTAL D&C AND STIMULATION COSTS	**€ 4,672,893**	**$5,192,103**
	EURO	**USD**
Steel Costs		
Casing Head (Fixed)	€ 22,950	$25,500
Conductor	€ 3,628	$4,031
Surface Casing	€ 37,566	$41,740
Intermediate Casing	€ 214,200	$238,000
Production Casing	€ 389,718	$433,020
Tubing	€ 63,000	$70,000
TOTAL STEEL COSTS	**€ 731,062**	**$812,291**
Labor Costs		
Consulting/Supervision	€ 100,934	$112,149
Drilling/Completion	€ 201,176	$223,529
Contract Labor	€ 190,097	$211,219
Fracturing	€ 157,366	$174,851
TOTAL LABOR COSTS	**€ 649,573**	**$721,748**
TOTAL WELL CAPEX	**€ 6,053,528**	**$6,726,142**

Source: own elaborations based on EIA, 2010

[5] All monetary amounts expressed in this report assume a conversion of € 0.90 per US Dollar (USD) (Exchange rate as of 3 July 2016.).

Table 9. Lease Equipment Costs for Oil Wells

Well Depth (feet)	Well Depth (meters)	Average Costs ($ (USD)/well)	Average Costs (Euro)/well)
2,000	610	$131,580	€ 118,422
4,000	1,219	$175,290	€ 157,761
8,000	2,438	$252,060	€ 226,854
12,000	3,658	$221,340	€ 199,206
10,007	**3,050**	**$236,700**	**€ 213,030**

Source: own elaborations based on EIA, 2010.

Table 10. Lease Equipment Costs for Gas Wells

Gas Production Lease Equipment Costs -- 50 Mcf per day, 1,415 cubic meters per day			
Well Depth (feet)	**Well Depth (meters)**	**Average Costs ($ (USD)/well)**	**Average Costs (Euro)/well)**
2,000	610	$34,600	€ 31,140
4,000	1,219	$34,600	€ 31,140
8,000	2,438	$44,100	€ 39,690
12,000	3,658	n.e.	n.e.
10,007	**3,050**	**$44,100**	**€ 39,690**
Gas Production Lease Equipment Costs -- 250 Mcf per day, 7,080 cubic meters per day			
Well Depth (feet)	**Well Depth (meters)**	**Average Costs ($ (USD)/well)**	**Average Costs (Euro)/well)**
2,000	610	$35,000	€ 31,500
4,000	1,219	$53,400	€ 48,060
8,000	2,438	$82,200	€ 73,980
12,000	3,658	$105,000	€ 94,500
10,007	**3,050**	**$93,600**	**€ 84,240**
Assumed rate of 100 Mcf/day		**$56,475**	**€ 50,828**
Gas Production Lease Equipment Costs -- 500 Mcf per day, 14,160 cubic meters per day			
Well Depth (feet)	**Well Depth (meters)**	**Average Costs ($ (USD)/well)**	**Average Costs (Euro)/well)**
	0	n.e.	n.e.
4,000	1,219	$62,000	€ 55,800
8,000	2,438	$80,500	€ 72,450
12,000	3,658	$101,400	€ 91,260
16,000	4,877	$108,400	€ 97,560
10,007	**3,050**	**$90,950**	**€ 81,855**
n.e. = not estimated			

Source own elaborations based on EIA, 2010

Table 11. Annual Operating Costs for Oil Wells

Well Depth (feet)	Well Depth (meters)	Average Costs ($ (USD)/well)	Average Costs (Euro)/well)
2,000	610	$21,660	€ 19,494
4,000	1,219	$27,060	€ 24,354
8,000	2,438	$39,890	€ 35,901
12,000	3,658	$37,150	€ 33,435
10,007	**3,050**	**$38,520**	**€ 34,668**

Source: own elaborations based on EIA, 2010

Table 12. Annual Operating Costs for Gas Wells

Gas Production OPEX -- 50 Mcf per day, 1,415 cubic meters per day			
Well Depth (feet)	**Well Depth (meters)**	**Average Costs ($ (USD)/well)**	**Average Costs (Euro)/well)**
2,000	610	$17,400	€ 15,660
4,000	1,219	$21,200	€ 19,080
8,000	2,438	$24,000	€ 21,600
12,000	3,658	n.e.	n.e.
10,007	**3,050**	**$24,000**	**€ 21,600**
Gas Production OPEX -- 250 Mcf per day, 7,080 cubic meters per day			
Well Depth (feet)	**Well Depth (meters)**	**Average Costs ($ (USD)/well)**	**Average Costs (Euro)/well)**
2,000	610	$22,400	€ 20,160
4,000	1,219	$33,500	€ 30,150
8,000	2,438	$55,400	€ 49,860
12,000	3,658	n.e.	n.e.
10,007	**3,050**	**$55,400**	**€ 49,860**
Assumed rate of 100 Mcf/day		**$31,850**	**€ 28,665**
Gas Production OPEX -- 500 Mcf per day, 14,160 cubic meters per day			
Well Depth (feet)	**Well Depth (meters)**	**Average Costs ($ (USD)/well)**	**Average Costs (Euro)/well)**
2,000	610	n.e.	n.e.
4,000	1,219	$34,500	€ 31,050
8,000	2,438	$40,400	€ 36,360
12,000	3,658	$49,600	€ 44,640
16,000	4,877	$51,500	€ 46,350
10,007	**3,050**	**$45,000**	**€ 40,500**
n.e. = not estimated			

Source: own elaborations based on EIA, 2010 ; based on EIA, 2010.

Gas Gathering and Compression Costs

The gas gathering component costs were established using data provided by industry experts. The gas gathering component cost is divided into three main systems:

- The low pressure delivery (or suction) pipe, which delivers gas from the well to the compressor phase.
- The compressor station (four compressor units), which includes all associated dehydrators, separators, meters, water containment units, compressor housing and noise abatement structures.
- The high pressure discharge pipe, which carries the compressed gas to the main gas pipeline.

The gas gathering model employs several further assumptions:

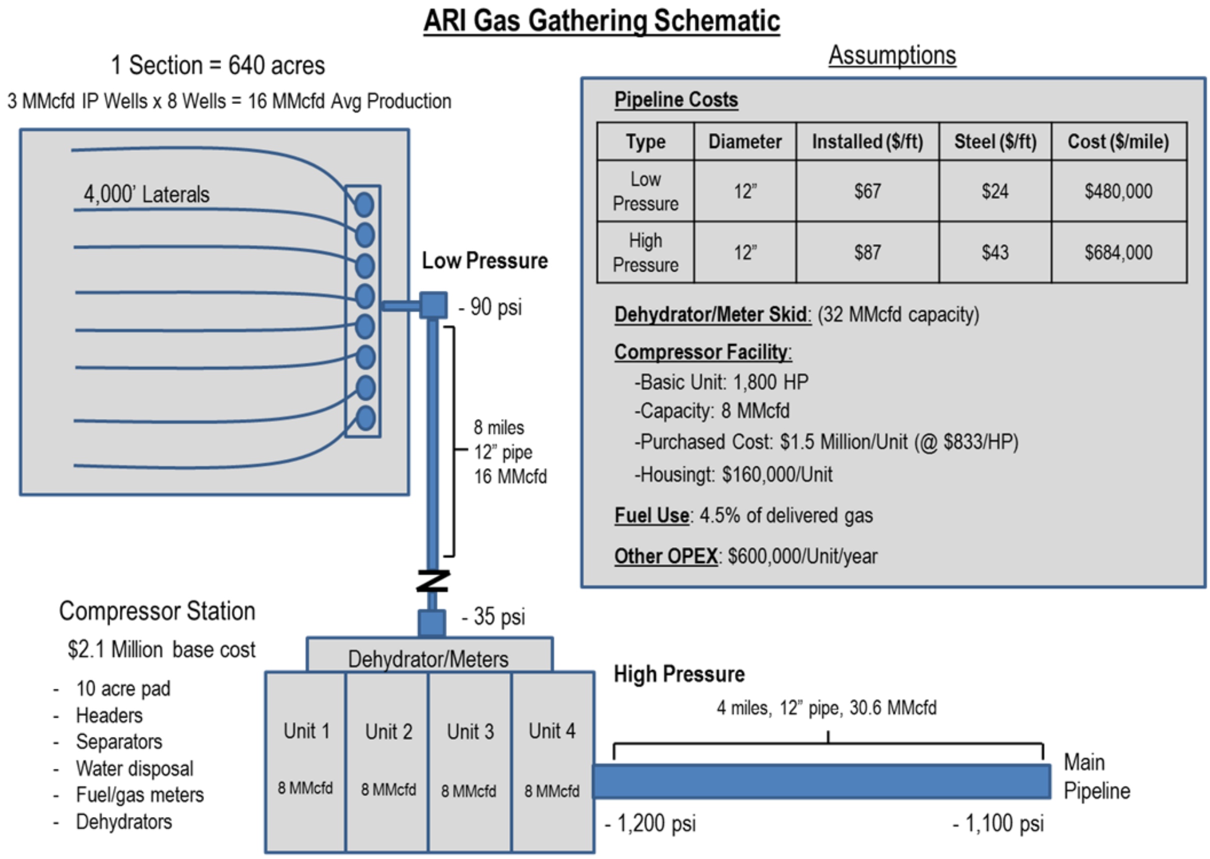
- Gas enters the delivery pipeline at 620 kilopascal (kPa) (90 psi), and is delivered to the compressor station at 241 kPa (35 psi).
- Gas is compressed to 8.27 kPa (1,200 psi) and is delivered to the main pipeline at 7.58 kPa (1,100 psi).
- The compressors utilize 4.5% of the delivered gas as fuel.
- Annual gas gathering and compression operating costs amount to of € 2.18 million per year.
- The gas gathering component provides gathering costs for four different initial well production rates: (28,300, 85,000, 142,000, and 283,000 cubic meters per day (1.0, 3.0, 5.0, and 10.0 MMcfd).

The amount of gathering infrastructure needed to develop a given area was established by using data from mature field development gathering systems. These data allowed for the determination of a "steady state" relationship between wells drilled and gas gathering infrastructure that represents a realistic estimate of the gathering requirements of a field-scale development. This "steady-state" ratio is used to determine the number of compressor units required for a given field. The number of gathering stations is based on the number of total compressors needed, assuming four compressor units per gathering station.

Figure 17 represents the gas gathering model used to calculate total gathering costs, which are then scaled based on a determined well spacing and total field acreage.

Table 13 shows gathering costs based on a 40 square kilometre (10,000 acre) development area, 125 wells, and an initial production rate of 85,000 cubic meters per day (3.0 MMcfd).

Figure 17. Representation of Methodology for Estimating Gas Gathering System Costs



Source: elaborations by Advanced Resources International.

Table 13. Summary of gathering System Costs for 40 km2 Development, with 125 Well, an Initial Production Rate of 142,000 cubic Meter per Day

CAPEX				
			EURO	**USD**
Compressor Station Costs				
Station Equipment			€ 7,560,000	$8,400,000
Compressors			€ 22,950,000	$25,500,000
Housing			€ 2,304,000	$2,560,000
Total			**€ 32,814,000**	**$36,460,000**
Pipe Costs	**Material Cost**	**Product Cost**		
Low Pressure Pipe	$4,055,040	$11,304,960	€ 13,824,000	$15,360,000
High Pressure Pipe	$3,632,640	$7,311,360	€ 9,849,600	$10,944,000
Total	**$7,687,680**	**$18,616,320**	**€ 23,673,600**	**$26,304,000**
Gas Gathering Cost Addition				
Total CAPEX			**€ 56,487,600**	**$62,764,000**
TOTAL CAPEX PER WELL			**€ 451,901**	**$502,112**
OPEX				
Annual OPEX - Labour Costs		80% of Total	€ 6,912,000	$7,680,000
Annual OPEX - Non- Labour Costs		20% of Total	€ 1,728,000	$1,920,000
Annual OPEX per Station				$9,600,000
Annual OPEX per Well - Labour Costs		80% of Total	€ 55,296	$61,440
Annual OPEX per Well -- Non Labour Costs		20% of Total	€ 13,824	$15,360
Annual OPEX per Well			€ 69,120	$76,800
FUEL COSTS				
Total Annual Fuel Costs			€ 7,152,365	$7,947,072
Annual Fuel Cost per Well			€ 57,219	$63,577
No. of Wells	**125**			

Source: own elaboration on modelling results

Regional Cost Factors

Costs will vary from country to country. The cost model takes this regional variation into account by utilizing an established construction cost price index. The U.S. Department of Defence Facilities Pricing Guide provides a cost index for constructing new installations in over 70 countries around the world (Unified Facilities Criteria (UFC), March 2016). This index takes into account availability of construction materials, labour availability, environmental conditions, and several other criteria. These indices were grouped by region, and then normalized to align with the well costs by applying the difference in cost of developing a shale well in the United States to a hypothetical, similar well in Europe. The regional cost factor is then applied to all well drilling and completion costs, labour rates, and steel product costs.

For Poland, this pricing guide reports an area cost factor of 1.55, while for Germany, an area cost factor of 1.05 is reported. However, in the cost model developed for U.S. EIA, the area cost factors were averaged to develop an overall cost factor of 1.55 for Western Europe, and 1.21 for Eastern Europe. For purposes of this study, we assumed a regional cost factor of 1.21 for assessing "up-side" commercial viability for both Germany and Poland, based on the assumption of "nth-of-a-kind" shale well installations. Initial "first-of-a kind" costs were assumed to be higher; for purposes of this report, "first-of-a kind" costs were assumed to be 2.5 times that for "nth-of-a-kind" costs, or three times US-based costs.

These factors are consistent with Advanced Resources' experience in supporting some of the early companies assessing shale resources in Poland and Germany. These factors are also supported by comparable work in a number of other basins in the US and around the world.

Possible Additional Costs for Environmental Protection

The cost estimates summarized above assume compliance with "best environmental management practices" as practiced in North America, as recommended by industry organizations such as the American Petroleum Institute. These costs include best practices for minimizing use of potable water, ensuring long-term well integrity, assuring safe disposal of frac water and other produced water, minimizing surface impacts, and effectively engaging regulators and other stakeholders.

In the case of the management and disposal of frac water and other produced water, costs represent a weighted-average cost representative of the spectrum of practices pursued in North America, including appropriate treatment, and reuse, surface disposal, or subsurface disposal. Understandably, such "best practices" may not necessarily be the same in Europe. However, given the economically marginal nature of the resources assumed in this assessment (described in more detail below), substantially higher water management costs would likely make these resources uneconomic, and thus, estimation of potential benefits unnecessary.

Similarly, actions associated with reducing methane emissions during well completion operations (i.e., using "reduced emissions completions," (RECs); sometimes referred to as "green completions," are also assumed to be included in the baseline costs. Regulations requiring their use have been in place for fractured gas wells for several years in the US, and have recently been extended to apply to fractured oil wells as well. Moreover, many companies were using RECs even before the new regulations required them. One study showed that the use of RECs adds about $60,000 (USD) (€ 54,500) to the cost of a well, representing on the order of about 1% of total well costs (ARI, 2012). The U.S. Environmental Protection Agency (USEPA) cost estimates for RECs are considerably lower, on the order of $17,000 (USD) (€ 15,500) per well (U.S. EPA, 2016).

One particular area not assumed to be addressed in the costs presented above are associated with costs targeting the reduction of methane emissions from other oil and gas E&P operations, not associated with fractured gas well completions.

Thus, additional costs were added for this assessment, as described in the following.

In May 2016, USEPA promulgated New Source Performance Standards (NSPS) (under section OOOOa) intended to curb emissions of methane and volatile organic compounds from additional new, modified and reconstructed sources in the oil and gas industry. In addition to promulgating new regulations requiring the use of RECs on all new hydraulically fractured oil wells (such completions were already required for hydraulically fractured gas wells), USEPA also promulgated new requirements for conducting regular, periodic surveys of fugitive emissions of methane and volatile organic compounds (VOCs) (equipment leaks) from well sites and gathering and boosting compressor stations (U.S. EPA, 2015). Complying with these requirements will impose additional costs on industry that are likely not represented in the cost assumptions described above. Thus, additional costs were added for this assessment, as described in the following.

For estimating costs of fugitive emissions monitoring and repair, the NSPS OOOOa Technical Support Document (TSD) (U.S. EPA, 2015) assumes a "model well site" based on the data on major equipment and equipment components provided an earlier study (Gas Research Institute and U.S. Environmental Protection Agency, June 1996). The TSD assumes two completed wells per well site and the baseline leak frequency is 1.18% of equipment components[6]. Seventy-five percent of leaks are assumed to be repaired immediately and 25 percent of leaks are repaired offline.

(ICF International, 2016) provides an analysis of marginal abatement cost (MAC) of various methane emission abatement technologies and work practices for the natural gas industry. The baseline for methane emissions from the natural gas sector in this study is the USEPA Inventory of Greenhouse Gas Emissions for 2012. This MAC analysis provides costs for fugitive emissions monitoring and repair at wells sites and installation of portable flares at gas wells with hydraulic fracturing, but not for reduced emissions completions.

This report takes a more comprehensive approach to estimating costs for leak detection and repair at well sites than the EPA NSPS OOOOa, and as a result have significantly higher annual compliance costs on a per well basis.

An hourly rate for fugitive emissions surveys is estimated by ICF to be $142/hour (USD), which includes labour, training and amortization of all capital equipment. This assumes that companies acquire a full range of leak detection and quantification equipment, including a Hi-Flow Sampler and OGI camera. It is unclear how many operators would do this. The report shows that 5.5 hours are assumed for each well site for each fugitive emissions survey. Thus, 5.5 hours x $142.06/hour = $781 (USD) per annual survey. Repair costs for leaking components are assumed to equal the inspection cost. An additional $156 per well site is added for initial set-up of the survey. It is unclear what initial set-up entails, but it might cover initial development of a monitoring plan.

The report concludes that the total annual cost, assuming 1 survey is $1,719 (USD) (€1,562). For semi-annual survey requirement, the annual cost estimated from the 2016 ICF report would be $3,282 (USD) (€ 2,983) per well site (well pad). The per-well cost would depend on how many wells are assumed per well pad.

The corresponding cost for semi-annual OGI fugitive emissions surveys per well site estimated by EPA would be:

> $800 capital cost per well site + $101 annual cost per well site = $901 (USD) per well site (first year cost)

EPA's cost estimate does not include the capital cost of acquiring an OGI camera or any other equipment needed for an OGI survey. USEPA assumes all emissions surveys are provided by a third-party. ICF's cost estimate is likely on the high side because many operators are unlikely to acquire all of the equipment specified. A reasonable estimate of

[6] The assumption of a 1.18% leak frequency rate is obtained from Table 5 in, (RTI International, 2011) . The document is available at https://www.regulations.gov/document?D=EPA-HQ-OAR-2002-0037-0180

likely costs for fugitive emissions surveys and repair, for the purpose of EU gas shale development, is probably somewhere between the two cost estimates.

Thus, for purposes of this assessment, an incremental cost to conduct periodic leak detection surveys is estimated to be $2,100 (USD) (€ 1,910) per well site per year.

Applicability of Estimated Costs for Other UH Resources

In general, these cost estimates for new shale oil and gas development and production should be generally applicable for other newly developed UH resources like low permeability (tight) gas sands and coal bed methane (CBM) resources.

In fact, for tight gas, they should be directly applicable. The future development of tight gas resources in Europe will likely be in less permeable, more difficult settings; settings quite similar to shale gas settings. Thus costs for well drilling and stimulation will be comparable.

For CBM, well depths would generally be more shallow, so drilling costs would probably need to be adjusted to account for the shallower depths. Moreover, CBM wells generally do not need to be as extensively hydraulically fractured as shale wells, so those costs are likely to be somewhat slower, perhaps reduced by about half.

Perhaps the biggest difference between shale wells and CBM wells relates to the large volumes of water produced in the initial stages of CBM development and production. In marginally economic CBM projects, water disposal costs and the associated environmental considerations can be a critical factor; water management and disposal costs for CBM can make or break a marginal project.

Water management and disposal costs include the energy (power) required to lift fluids up a wellbore, manage it on the surface, treat it, and properly dispose of it. A rule of them for fluid lifting costs is € 0.25 per barrel of fluid lifted (Bailey , Crabtree, Tyrie , & Elphic, 2000). Another € 0.50 per barrel could be added for surface treatment and reinjection.

Higher costs, however, may be required for Europe, especially if reinjection of produced water is not an option. For example, (Jackson & Myers, Oct. 16-17, 2002.) and (Jackson & Myers, Oct. 5-8, 2003) provided cost estimates for many produced water disposal methods that might be used in Rocky Mountain States. They reported produced water management costs for secondary recovery ranging from € 0.45 to € 1.13 per barrel ($0.05 to $1.25 per barrel), and for shallow reinjection of € 0.09 to € 0.45 per barrel ($0.10 to $1.33 per barrel). More sophisticated water treatment and reuse options could be considered. However, the costs associated with such applications can vary widely, and depend on produced water characteristics and the application for which the produced water will be used. Such applications can range from reuse in oil and gas operations (for example, as a source for water used in hydraulic fracturing, industrial applications, agricultural applications (irrigation or livestock), hydrological uses (such as subsidence or salt water intrusion control), or can be treated to drinking water standards. Veil, et al. provides a discussion of such options (Veil, Harto, & McNemar, 21-23 March 2011).

A comprehensive evaluation of the costs associated with such a diverse set of water treatment options is beyond the scope of this assessment. As described above, in this assessment the costs assumed for the management and disposal of frac water and other produced water represent a weighted-average cost representative of the spectrum of practices pursued in the US, including appropriate treatment, and reuse, surface disposal, or subsurface disposal.

Oil and Gas Fiscal Regimes

Assumptions regarding the fiscal regime for unconventional oil and gas production in Poland and Germany were determined based on that described in the 2015 version of the EY Global Oil and Gas Tax Guide (EY, 2015). Representation of these tax regimes was simplified somewhat for purposes of assessing the economic potential of the future development of UH resources in these two countries.

Poland

In Poland, a new law concerning the regulatory and tax framework for the exploration and extraction of hydrocarbons came in force in 2016. The law introduces a hybrid model of taxation consisting of a special hydrocarbons tax chargeable on a cash basis (cash flow tax), and an *ad valorem* royalty (i.e., the tax on the extraction of selected minerals). Other key areas of the new tax law relate to changes in the concession-granting system and significant changes to concessions transfers and trading.

The new *ad valorem* royalties will not be payable until 2020. In this study, it was assumed that it would be in effect by the time any new, large-scale UH development and production commences in Poland.

The new law established a Special Hydrocarbons Tax (SHT) based on the excess of sale revenues over eligible expenses related to the hydrocarbons extraction business, both onshore and offshore, with rates linked to investor returns. The SHT will be charged based on a cash basis, with some exemptions. The tax rate is based on the ratio of cumulative revenues to cumulative costs from the beginning of the entity's extraction. For this assessment, for simplification purposes, the tax rate is assumed to be zero until this ratio becomes greater than 2.0; where then the full tax rate of 25% would apply

A royalty or *ad valorem* tax is also chargeable on the extraction of natural gas and oil. The tax rates are as follows:

- For natural gas — 1.5% (unconventional deposits), 3% (conventional deposits)
- For oil — 3% (unconventional deposits), 6% (conventional deposits).

Finally, corporations operating in Poland are subject to a corporate income tax (CIT) on their Polish-sourced income, at a rate of 19%. This rate applies to any type of income, including that from oil and gas activities.

The relationship between CIT, SHT and the royalty tax is as follows:

- Neither SHT nor royalty tax will be a deductible cost for CIT purposes
- Paid CIT and royalty tax related to oil and gas exploration activities will be deductible for SHT purposes (being eligible costs)
- 19% of cumulative CIT losses from extraction activities which have not been carried forward in whole (because of the expiry of the five-year period) will be deductible from the royalty tax.

The relevant tax assumptions for Poland assumed in this study are summarized in Table 14.

Table 14. Oil and Gas Tax Regime Assumptions for Poland

Tax Element	Rate	Notes
Special Hydrocarbons Tax (SHT)	25.0%	Applies when the ratio of cumulative revenues to cumulative expenses >2.0.
***Ad valorem* Royalty -- Gas**	1.5%	For unconventional gas
***Ad valorem* Royalty -- Oil**	3.0%	For unconventional oil
Corporate Income Tax (CIT)	19%	SHT or royalty NOT deductible cost for CIT purposes
Depreciation		Straight line assumed
Wells	4.5%	Over 22 years?
Equipment	20.0%	Assumes accelerated depreciation -- for 5 years

Source: (EY, 2015)

Germany

The fiscal regime that applies to all industry in Germany consists of a combination of royalties and corporate profits tax, i.e. corporate income tax, solidarity surcharge and trade tax. In principle, there is no special taxation regime applicable to the oil and gas industry in Germany.

The overall combined corporate profits tax rate amounts ranges from 22.8% up to 34% (with an average of 29.8%, which is assumed in this report).

Royalties are imposed annually at the individual state level and can vary between 0% and 40% based on the market value of the produced oil or gas at the time of the production. The royalties can be deducted from the tax base for German corporate income tax and trade tax purposes. A 30% rate for Lower Saxony was assumed in this study.

The relevant tax assumptions for Germany are summarized in Table 15

Income Taxes on Wages/Salaries of Oil and Gas Workers

One additional benefit associated with the oil and gas jobs created from new UH resource development is that these workers will be required to pay income taxes. In Germany, for purposes of this assessment, an income tax rate for oil and gas workers of 42% was assumed (Trading Economics, 2016) and (Confederation Fiscale Europeenne, 2016). For Poland, an income tax rate for oil and gas workers of 32% was assumed (Trading Economics, 2016) (European Union).

Table 15. Oil and Gas Tax Regime Assumptions for Germany

Tax Element	Rate	Notes
Corporate Income Tax (CIT)	29.8%	Overall combined corporate profits tax, rate, which includes corporate income tax, solidarity surcharge and trade tax.
Royalties		Royalties can be deducted from the tax base for German corporate income tax and trade tax purposes.
Lower Saxony		
Oil	18.0%	
Gas	30.0%	
Schleswig-Holstein		
Oil	40.0%	
Gas	40.0%	
Depreciation	6.667%	Straight line assumed -- 15-year asset life

Source: (EY, 2015)

Project-Specific Economics

Prospect-specific economic analyses were performed using an industry standard cash flow model. The key inputs and assumptions of the cash flow model include oil and natural gas prices; and assumed rates for royalties, *ad valorem* taxes, and income taxes. This is in addition to all the costs associated with new UH production, including all capital expenditures (CAPEX) and operating expenditures (OPEX) applicable.

The initial set of prospect-specific economic evaluations performed for the representative productivity scenarios described in the previous section assumed the costs described earlier, with an assumed 1.21 cost adjustment factor relative to US costs. While it is recognized that this may be optimistic, is was assumed here to characterize possible upside potential in terms of economic and employment benefits. Similarly, the level of regulatory/environmental compliance requirements and the timing of project development (leasing, drilling, etc.) was assumed to be similar to that in North America, at least for this optimistic case.

This corresponds to a case where the so-call "sweet spots" have been discovered, industry recovery and cost efficiencies are being realized, and development and production have become routine, predictable, and efficient. Resource development under this set of conditions, consistent with historical experience, is assumed to be representative of only a very small portion of the total future UH resource potential.

This does not characterize the case corresponding to early drilling and development activities, where resource understanding, well drilling practices, and development efficiencies may still be a challenge, and costs are likely to be considerably higher than this, perhaps on the order of two to three times higher.

Critical to the economic prospectivity of new UH resources are the oil and gas prices these resources can realize at the wellhead. Since 2005, according to EIA, Brent crude oil spot prices (FOB) have ranged from € 47 to € 100 per barrel ($52 to $112 per barrel), with an average of € 75 per barrel ($83 per barrel) (U.S. EIA, 2016).

For natural gas, since 2008, natural gas prices in both Poland and Germany have averaged about € 0.04 per kilowatt-hour (kwh), or about $13 per million Btu (MMBtu) (Communication from The Commission to The European Parliament, The Council, The European Economic and Social Committee and The Committee of the Regions, 29 January, 2014).

Thus, for purposes of this assessment, the assumed price scenarios represent the range of prices occurring over the last 10 years. For natural gas, two price cases were assumed: (1) $13.00 per MMBtu (€ 332 per cubic meter); and (2) $20.00 per MMBtu (€ 510 per cubic meter).

For oil/condensate, two prices cases were also assumed: (1) $83 (€ 75) per barrel and (2) $112 (€ 101) per barrel.

A 10% cost of equity, or minimum required rate of return on equity, was assumed. Projects were required to meet this hurdle in order to achieve economic/commercial viability.

Economic Resources -- Poland

For purposes of this assessment, the economic potential of a representative well in the assumed "sweet spot" in Poland's North Baltic Basin was considered under the three assumptions for an average EUR per well -- the Base (or Most Likely) Case EUR, the High Case EUR, and a case where the EUR is assumed to be twice the High Case. The rationale for the highest case is that it could possibly represent the case where substantial improvements in recovery due to increased resource understanding and improved technologies and production practices are realizable. Moreover, as shown below and in

Table 16, economic/commercial viability would likely not be achievable under the Low Case EUR.

Table 16. Economic Potential of the Assumed "Sweet Spot" in Poland's North Baltic Basin

Characterization of Economic Resources -- Poland					
Natural Gas					
	Gas Price			**Net Present Value**	
	$/Mcf	**Euros per kwh**	**IRR (%)**	**1000 USD ($)**	**1000 Euros**
Most Likely EUR					
Average	$13.00	€ 0.0399	9%	-$1,721	-€ 1,549
Alternative	$20.00	€ 0.0614	10%	-$83	-€ 75
High EUR					
Average	$13.00	€ 0.0399	11%	$1,322	€ 1,190
Alternative	$20.00	€ 0.0614	12%	$4,599	€ 4,139
2 X High EUR					
Average	$13.00	€ 0.0399	12%	$6,943	€ 6,249
Alternative	$20.00	€ 0.0614	13%	$6,990	€ 6,291
Oil/Condensate					
	Oil Price			**Net Present Value**	
	$/Barrel	**Euros per kwh**	**IRR (%)**	**1000 USD ($)**	**1000 Euros**
Most Likely EUR					
Average	$83.00	€ 74.70	7%	-$3,426	-€ 3,083
High	$112.00	€ 100.80	7%	-$2,999	-€ 2,699
High EUR					
Average	$83.00	€ 74.70	11%	$2,911	€ 2,620
High	$112.00	€ 100.80	12%	$5,328	€ 4,795
2 X High EUR					
Average	$83.00	€ 74.70	13%	$9,033	€ 8,130
High	$112.00	€ 100.80	13%	$10,985	€ 9,887
Euro/USD conversion	0.9	7/3/2016			
MMBtu/kwh	0.00341				

Source: own elaborations on modelling results .

If the basin proves to be natural gas-prone, under the Most Likely Case EUR per well, economic viability would likely not be achievable at either of the natural gas prices assumed. Of course, the same would be true under the Low Case EUR. Only if per well EURs approach the High Case, or higher, can economic viability be achieved. Also, as shown in Table 16, the same applies if the basin proves to be more liquid prone.

Economic Resources -- Germany

Similarly, for the assumed "sweet spot" in Germany's Lower Jurassic Posidonia Shale, if the resource proves to be natural gas prone, which is expected to be likely, under the most likely case EUR per well, economic viability would not appear to be achievable at either of the natural gas price scenarios assumed. Only if per well EURs approach the High Case, or higher, can economic viability be achieved (Table 17).

In conclusion, this analysis shows that even the resources characterized as being in the "sweet spot" are likely to be marginally economic at best assuming the Most Likely Case EUR. And this "sweet spot" was defined in the plays that are most likely to be commercial. Thus, further economic evaluation of the resources in the other plays was not warranted.

Consequently, for purposes of this assessment of the country-wide economic impacts and framework conditions for new potential unconventional gas and oil extraction in Germany and Poland, these benefits will only be fully realizable if per well productivity exceeds that associated with most the Most Likely case defined previously, and only in areas defined as the "sweet spots."

Table 17. Economic Potential of the Assumed "Sweet Spot" in Germany's Lower Jurassic Posidonia Shale

Characterization of Economic Resources -- Germany					
Natural Gas					
	Gas Price			**Net Present Value**	
	$/Mcf	**Euros per kwh**	**IRR (%)**	**1000 USD ($)**	**1000 Euros**
Most Likely EUR					
Average	$13.00	€ 0.0399	9%	-$462	-€ 416
Alternative	$20.00	€ 0.0614	11%	$610	€ 549
High EUR					
Average	$13.00	€ 0.0399	11%	$1,529	€ 1,376
Alternative	$20.00	€ 0.0614	12%	$3,673	€ 3,306
2 X High EUR					
Average	$13.00	€ 0.0399	13%	$5,511	€ 4,960
Alternative	$20.00	€ 0.0614	14%	$9,799	€ 8,819
Euro/$ conversion	0.9	7/3/2016			
MMBtu/kwh	0.00341				

Source: own elaborations on modelling results

Project Life Cycle, Activities, And Labour Requirements

Project Life Cycle

A wide range of definitions for the project life cycle for new UH resource development is possible. In many ways, the characterization of the project life cycle depends on the purpose it serves. For example, (Branosky, Stevens, & Forbes, 2012) defined a shale gas project life cycle that focuses on the mitigation of environmental impacts. Some companies use the project life cycle to describe the phases of the oil and gas activities for corporate accountability reports (Cairn Energy PLC, 2010) or in describing the services they offer (SGS, Société Générale de Surveillance) and (Clough, 2014).

In this assessment, the key stages of the project life cycle for a new UH resource project are specified primarily for the purpose of assessing personnel requirements in each aspect of oil and gas exploration, development and production, and are assumed to consist of the following:

<u>First 4 – 7 years</u>

- Initial basin evaluation
- Leasing
- Asset evaluation (exploration seismic, site surveys, baseline environmental assessments) for target location)
- Exploration drilling

<u>Next 5 - 15 years</u>

- Appraisal drilling (field delineation, prospect confirmation, well testing)
- Site preparation and development
    - Site preparation
    - Development well drilling
    - Hydraulic fracturing
    - Well completion
    - Facilities construction

<u>Next 8 -30 years</u>

- Production operations
    - Further development/infill drilling
    - Refracking/recompletions/well workovers
    - On-site processing

<u>Last 2 – 8 years</u>

- Decommissioning – Site closure, well closure, site remediation

It should be noted that, for purposes of this assessment, transmission/transport, off-site processing, refining and storage, and distribution and marketing were not considered.

Life cycle and supply chain considerations are evaluated at two points in time:

1. In the early stages of new UH resource development in a basin or play, in particular, when early evaluation activities are underway, and when a substantial amount of non-local consultation, services, and expertise would be called upon.

2. In the later, more mature stages of new UH resource development in the basin or play, where the early evaluation activities are no longer required, and where the majority of personnel and services are supplied from local sources.

It is important to note that the pace of many of these activities may be different in the EU than in North America. In particular, a number of non-economic factors will need to be taken into account. Thus, more traditional econometric approaches that estimate the pace of drilling as a function of new UH resource economics and forecast oil and gas prices based primarily on the US experience are probably less appropriate, or may need to be modified significantly to apply to the EU.

For example, the EU currently lacks substantial numbers of drilling rigs and fracking fleets, all of which will initially have to be deployed from non-EU suppliers. However, as development matures, more of this capability should become available within the EU.

The specific infrastructure and supply capabilities to service new UH resource development in EU member states is the subject of another study, and not the focus of this assessment.

Another area where the US experience probably may not translate well to the EU regards the timing of new UH resource development. In the US., mineral rights are generally privately-held, and negotiating with mineral right owners and aggregating lands pertaining to these rights can be a time consuming and costly front-end effort. Mineral rights are administered and granted by the federal government in all EU nations, including Germany and Poland, and not by the landowners, like in most of the US. Stakeholder discussions, however, in aggregate, may not be that different between the EU and the US. The more complex and time consuming decision-making process for exploration and production licenses in Europe may replace the slow, methodical process in the US for aggregating mineral rights and negotiating with land owners.

The personnel and resources associated with the project life cycle phases associated with basin analysis; leasing, acquisition, and permitting; and asset evaluation would only apply when development in the basin is relatively immature. The personnel and resources associated with site construction, drilling, hydraulic fracturing, extraction and production would apply both in the early and more mature stages of development, though their contribution would evolve as the transition toward more mature development takes place.

Nonetheless, in this assessment, one development schedule was assumed to characterize an aggressive (from the scale or benefits realization) scenario. A more moderate pace is certainly likely, with the economic and employment benefits accordingly accruing more slowly. In this case, another case was considered that assumed a pace of development one-third as fast as the more aggressive scenario.

Project Activities and Labour Requirements for Benefits Estimation

Personnel and resources are estimated based on the specific activities and requirements associated with each of the activities in each of the stages of the project life cycle. For example, personnel and resources are developed on a specific unit basis, such as the number of wells drilled or on production. This is in contrast to what is generally assumed in standard input-output models, such as employment levels as a function of total capital expenditures or revenues from hydrocarbon sales.

In this assessment, as a first step, specific job titles and descriptions to be considered needed to be defined. A number of sources were consulted in this exercise.

A 1979 study by the National Petroleum Council in the US defined a variety of job activities associated with the exploration, development, and production of oil and gas resources (National Petroleum Council, 1979). A list of job profiles associated with shale gas development, production and associated activities also has been developed by the Marcellus Shale Coalition (Marcellus shale coalition, 2016). The Canadian Government also publishes a list of job titles for oil and gas well drilling workers and service company personnel (Gov. of Canada, 2016).

Based on a review of these citations, the list of job titles considered in this assessment is summarized in Table 18.

Table 18. Job Titles for Job Creation Considered in this Assessment

Abstractor/Title Examiner	Heavy Equipment Operator	Roustabout
Lease/Land Agent	Environmental Tech	Welder
Surveyor	Geologist	Compressor Operator
GIS Specialist	Geochemist	Electrician
Surveyor's Asst.	Geophysicist	Lease Hand
Mud Logger	Geo Tech	Petroleum Eng.
Wireline Operator	Derrick Hand	Prod. Foreman
Electronics Tech.	Driller	Pumper/Well Tender
Drilling Rig Operator	Floor/Rig Hand Roughneck	Cementing/Frac Supervisor
Service Rig Operator	Mechanic	Cementing/Frac Hand
Truck Driver		

Source: own elaborations on modelling results

Important is distinguishing activities that generate new jobs, compared to those that just pertain to reassignments of existing jobs (particularly expat or home office jobs) within a company (especially in the early stages) (e.g., initial basin evaluation, leasing, and asset evaluation (exploration seismic, site surveys, baseline environmental assessments)).

The next step involved defining which of these jobs were performed at different phases of operation. The assumed breakdown of job titles by phase of operations/area of activity is shown in Table 19. The basis for the timelines assumed for each phase of operations is discussed in more detail below.

The next step involved defining the units of activity for which job categories apply (per lease, per well, per day, per frac job, etc.). These assumptions are shown in Table 20.

Table 19. Job Titles by Phase of Operations

	First 4 – 7 years			
	Initial basin evaluation	Leasing	Asset evaluation	Exploration drilling
Abstractor/Title Examiner		x		
Lease/Land Agent, "Landman"		x		
Surveyor			x	x
GIS Specialist	x	x	x	x
Surveyor's Assistant			x	x
Mudlogger				x
Wireline Operator				x
Electronics Technician				x
Rig Operator (drilling/service)				x
Truck Driver	x		x	x
Heavy Equipment Operator				x
Environmental Technician	x		x	x
Geologist	x		x	x
Geochemist	x		x	x
Geophysicist	x		x	x
Geo Tech	x		x	x
Derrick Hand				x
Drillier				x
Floor Hand/Roughneck/ Rig Hand				x
Mechanic				x
Roustabout				x
Welder				
Compressor Operator				
Electrician				x
Lease Hand				x
Petroleum Engineer				x
Production Foreman				
Pumper/Well Tender				
Cementing/Fracturing Supervisor				x
Cementing/Fracturing Hand				x
	7	**3**	**9**	**24**

Source: own elaborations on modelling results .

Table 19. Job Titles by Phase of Operations **(Continued)**

	Next 5 - 15 years					
	Appraisal drilling	Site prep	Development well drilling	Hydraulic fracturing	Well completion	Facilities construction
Abstractor/Title Examiner						
Lease/Land Agent, "Landman"						
Surveyor		x				x
GIS Specialist	x					x
Surveyor's Assistant	x	x				x
Mudlogger	x		x			
Wireline Operator	x		x	x		
Electronics Technician	x		x			x
Rig Operator (drilling/service)	x		x	x	x	
Truck Driver	x	x	x	x	x	x
Heavy Equipment Operator	x	x		x		x
Environmental Technician	x	x	x	x	x	x
Geologist	x		x	x	x	
Geochemist	x		x	x	x	
Geophysicist	x		x	x	x	
Geo Tech	x		x	x	x	
Derrick Hand	x		x	x	x	
Drillier	x		x			
Floor Hand/Roughneck/ Rig Hand	x	x	x	x	x	x
Mechanic	x	x	x	x	x	x
Roustabout	x		x	x	x	
Welder		x	x			x
Compressor Operator						x
Electrician		x				x
Lease Hand	x	x	x	x	x	x
Petroleum Engineer	x		x	x	x	x
Production Foreman						
Pumper/Well Tender			x	x	x	
Cementing/Fracturing Supervisor	x		x	x	x	
Cementing/Fracturing Hand	x		x	x	x	
	22	10	21	18	16	14

Source: own elaborations on modelling results

Table 19. Job Titles by Phase of Operations **(Continued)**

	Next 8 -30 years				Last 2 – 8 years
	Production ops	Development/ infill drilling	Refrack/ recomplete/ workovers	On-site processing	Decommissioning
Abstractor/Title Examiner					
Lease/Land Agent, "Landman"					x
Surveyor					x
GIS Specialist		x			
Surveyor's Assistant					x
Mudlogger		x	x		
Wireline Operator		x	x		
Electronics Technician	x			x	
Rig Operator (drilling/service)		x	x		
Truck Driver	x	x	x	x	x
Heavy Equipment Operator		x			x
Environmental Technician	x	x	x	x	x
Geologist		x	x		
Geochemist		x	x		x
Geophysicist		x	x		
Geo Tech		x	x		
Derrick Hand		x	x		x
Drillier		x			
Floor Hand/Roughneck/ Rig Hand	x	x	x	x	x
Mechanic	x	x	x	x	x
Roustabout		x	x		x
Welder	x			x	
Compressor Operator	x			x	
Electrician	x			x	
Lease Hand	x	x	x	x	x
Petroleum Engineer	x	x	x	x	x
Production Foreman	x	x	x	x	x
Pumper/Well Tender	x	x	x		
Cementing/Fracturing Supervisor	x	x	x		
Cementing/Fracturing Hand	x	x	x		
	14	22	19	11	14

Source: own elaborations on modelling results

Table 20. Units of Activity for Which Job Categories Apply

Phase/Area of Activity	Unit of Appraisal	Frequency
First 4 – 7 years		
Initial basin evaluation	Basin	One time
Leasing	Site	One time
Asset evaluation	Site	One time
Exploration drilling	Site, per exploration well	One time
Next 5 - 15 years		
Appraisal drilling	Site, per delineation well	Wells per Year
Site preparation	Site	One time
Development well drilling	Site, per development well	Wells per Year
Hydraulic fracturing	Site, per development well, per frac	Wells per Year
Well completion	Site, per development well	Wells per Year
Facilities construction	Site	One time
Next 8 -30 years		
Production operations	Site, per well workover	Per Well Per Year
Further dev./infill drilling	Site, per infill well	Per Well Per Year
Refrack/recomp./workovers	Site, per well workover	Per Well Per Year
On-site processing	Site	Per Year
Last 2 – 8 years		
Decommissioning	Site	One time

Source: own elaborations on modelling results.

Labour Requirements and Other Economic Benefits – "Bottom Up" Assessment

Two types of approaches can be pursued to assess the employment and other economic benefits associated with UH development – "bottom up" approaches, and "top down" approaches.

As recognized by (Weijermars, 2013), the economic impacts of UH development must be determined based on realistic field development plans for UH resource development specific to the EU, and that development plans must be based on realistic estimates of well productivity, price volatility, and field development costs to ensure economic viability. A "bottom up" approach, based on geologic, technological, and economic information/data on UH basins in Poland and Germany ensures this.

Moreover, (Kinnaman, 2010), noted that, as applied to the Marcellus shale in the eastern US, there is a concern that "top down" input-output models work best when considering modest "marginal" changes in economic activity. In the case of the EU, substantial amounts of direct spending will be required. This will likely be considerably different than the relationships within traditional, "top down" input-output models, which could very easily alter estimated impacts. This would be a concern in the EU, where the new UH resource development would potentially just be getting underway.

Several studies have reported employment impacts from UH resource development on a more "bottom-up" basis – such as expressing potential employment and economic benefits on a per well basis. For example, the study of the economic impacts of oil and gas development on federal lands in the western US (SWCA Environmental Consultants, 2012) developed employment estimates for both drilling and production operations on a per well basis. These estimates are summarized in Table 21.

A study examining the recent economic benefits of oil and gas development and production in the U.S. state of Mississippi (John C. Stennis Institute of Government, 2013), along with estimated potential future economic impacts associated with the development of the Tuscaloosa Marine Shale in the state, shows that one €13,500,000 ($15,000,000) well generates 66.2 total jobs, of which 22.2 are direct jobs. Of the remainder, 25.4 are indirect jobs, and another 18.5 are induced jobs. (This amounts to 490 jobs per € 100 million in industry expenditures).

These estimates for Mississippi are about twice the estimates for the US Federal lands for direct jobs, and three times that for total jobs (including indirect and induced). However, well costs assumed in the Mississippi assessment were also about three times those for US Federal Lands. Moreover, these costs are probably more in line with what would be expected to be incurred in Poland and Germany, at least initially.

Table 21. Economic and Employment Impact Estimates for Drilling and Production Operations on a Per Well Basis on U.S. Federal Lands

Impacts from Drilling a Typical Oil and Gas Well			
	Wyoming	Utah	Average
Total Cost (direct effect)	€ 3,948,534	€ 3,948,534	€ 3,948,534
Indirect Effect	€ 245,164	€ 536,145	€ 390,654
Induced Effect	€ 484,982	€ 1,038,083	€ 761,532
Total Economic Activity	€ 4,678,680	€ 5,522,762	€ 5,100,721
Employment (AJE)			
Direct	10.4	11.9	11.2
Indirect and Induced	7.0	15.2	11.1
Total	17.4	27.1	22.3
Total Labour Income	€ 1,157,967	€ 1,400,429	€ 1,279,198
Avg Labour Income per AJE	€ 66,550	€ 51,676	€ 57,492
Jobs/million Euro	372	491	436
Impacts of Production from a Typical Oil and Gas Well			
	Wyoming	Utah	Average
Total Cost (direct effect)	€ 2,209,578	€ 1,450,633	€ 1,830,105
Indirect Effect	€ 354,933	€ 271,543	€ 313,238
Induced Effect	€ 486,115	€ 649,760	€ 567,938
Total Economic Activity	€ 3,050,627	€ 2,371,936	€ 2,711,281
Employment (AJE)			
Direct	9.7	7.2	8.5
Indirect and Induced	6.9	8.9	7.9
Total	16.6	16.1	16.4
Total Labour Income	€ 1,123,841	€ 877,897	€ 1,000,869
Avg Labour Income per AJE	€ 67,701	€ 54,528	€ 61,215
Jobs/million Euro	544	679	603

AJE = Annual Job Equivalent
Source: (SWCA Environmental Consultants, 2012)

In addition, the Mississippi state impacts assessment also reported the following:

- Approximately 800 worker-days are required to construct a well, which includes drilling the well, and constructing access roads and gathering systems. On average, approximately 5 people, predominantly equipment operators, are required for well pad construction.
- Drilling activities for an individual well required about 12 workers, and it takes approximately 45 days to drill a well. Well completion takes approximately 15

workers, and may take between 30 to 54 days, depending on well depth and the number of completion zones. Approximately 10 to 25 workers are required to install pipeline gathering systems.

- It may take 10 to 25 workers to construct trunk roads, over a period of 30 days (assuming 1.5 miles of road per day, with 45 miles of roads required).

Labour Requirements Associated with Materials Transport

If UH resource development takes place in Poland and Germany, additional activities, volumes, and labour requirements will be associated with transport of major materials to the well site. The largest volumes, and the most significant contributor to labour requirements, will be associated with drilling and hydraulic fracturing operations. *In the estimates developed above, the labour requirements for materials transport to support these operations were assumed to be included in the indirect labour estimates.*

Oil and Gas Industry Employee Compensation

A final factor in determining economic benefits directly associated with job creation are the salaries that would be assumed for those new jobs, particularly the expected salaries in Poland and Germany (which may be different that comparable US salaries).

One source of salary data is the salary survey of professional geologists published by the American Association of Petroleum Geologists (AAPG). A summary of the salaries for 2014 is provided in Table 22. (AAPG does not report data by region or country.

Table 22. Annual Salaries for Petroleum Geologists for 2014

	Annual Salary		
Years of Experience	**High**	**Average**	**Low**
0-2	€ 105,570	€ 92,610	€ 78,300
3-5	€ 126,000	€ 103,410	€ 88,200
6-9	€ 146,880	€ 133,470	€ 121,500
10-14	€ 186,300	€ 149,040	€ 118,800
15-19	€ 185,400	€ 170,100	€ 139,500
20-24	€ 283,500	€ 210,870	€ 166,860
25+	€ 382,500	€ 206,910	€ 166,500
Average	**€ 202,307**	**€ 152,344**	**€ 125,666**

Source: American Association of Petroleum Geologists, 2014; see Stefanic, 2015

On average, these result in hourly rates ranging from € 60.42 to € 97.26, with an average of € 73.25.

Similarly, the Society of Petroleum Engineers (Society of Petroleum Engineers, 2014) reports annual salary data for those in the petroleum industry. Fortunately, the results of their survey break down salaries by region. As shown in Table 23, salaries in Europe are substantially lower, on average, than the international average, or the average for the U.S.

Table 23. Annual Salaries for Petroleum Engineers for 2014

	Total	USA	Africa	Oceania	Canada	Middle East	North Sea	N. and C. Asia	Latin America	Europe	SE Asia
Executive/Top Management	€ 386,147	€ 504,000	€ 527,108	€ 227,676	€ 295,395	€ 261,001	€ 387,438	€ 342,360	€ 583,230	€ 101,867	€ 352,752
Manager/ Director	€ 268,279	€ 364,487	€ 242,269	€ 178,702	€ 215,894	€ 219,810	€ 166,500	€ 172,053	€ 155,102	€ 179,939	€ 242,042
Supervisor/ Superintendent/ Lead	€ 214,006	€ 160,079	€ 188,384	€ 138,102	€ 176,343	€ 164,005	€ 146,209	€ 109,453	€ 135,720	€ 144,694	€ 175,132
Professional/ Individual Contributor	€ 181,445	€ 166,808	€ 144,265	€ 106,806	€ 149,471	€ 116,783	€ 99,857	€ 67,155	€ 93,949	€ 89,440	€ 149,175
Technician/ Specialist/ Support Staff	€ 139,186	€ 95,036	€ 64,714	€ 117,806	€ 162,638	€ 97,979	€ 49,678	€ 85,954	€ 83,235	€ 49,672	€ 110,350

Source: (Society of Petroleum Engineers, 2014)

For example, in the Supervisor/Superintendent/Lead category (the category most applicable to supervisory personnel at exploration and development sites, average hourly rates in the US were € 76.95 while for Europe, these rates were € 69.56, or about 10% lower.

Other industry sources were utilized to determine other oil field costs. One source reported earnings for oil rig floor hands (Fracking Jobs, 2016). Based on the results of the survey conducted for this article, this source concluded that:

- Roustabouts earn, on average, about € 14.77 per hour, or assuming 2,080 hours per year, € 30,720 annually.
- Derrick operators earn, on average, about € 20.30 per hour, or assuming 2,080 hours per year, € 42,214 annually.
- Rotary drillers earn, on average, about € 21.29 per hour, or assuming 2,080 hours per year, € 44,292 annually.

The Hays Oil & Gas Global Salary Guide for 2015 (Hays, 2016) reported that, for 2014, the global salaries for oil and gas workers averaged € 74,015. This breaks down into a local talent average of € 64,412 and an expat talent average of € 89,112. Salaries in Europe were 20% to 25% lower than those in North America for expat personnel, and 25% to 30% lower for local personnel.

Finally, the average contractor day rate globally in 2014 was € 486 per day. The day rates in North America and Western Europe were comparable. However, for Eastern Europe, day rates where roughly two-thirds those in North America.

"Bottom Up" Assessment of Labour Requirements and Other Economic Benefits

The final step is to determine the number of units of activity to assume for which personnel requirements are estimated. This needs to be considered separately for each of the major time phases. Specifically:

- First 4 – 7 years, where initial basin evaluation, leasing, asset evaluation, and exploration drilling takes place.
- Next 5 – 15 years, during which time appraisal drilling, site preparation. development well drilling, completion and fracturing takes place, along with facilities construction.
- Next 8 - 30 years, during which production operations occur, along with further development/infill drilling and well workovers. (Note that this does not necessary represent the life of an individual well (though many wells producing UH resources have produced 30 years or longer), but that for all wells under production in the field.)
- The last 2 – 8 years, where final decommissioning, site closure and remediation takes place.

Considering each of these phases separately is useful to be able to develop benefits assessments for alternative success scenarios for each country. Specifically, these alternative success scenarios are:

- Quickly abandon exploration -- if initial basin evaluation activities prove unfruitful.
- Explore but no development – initial basin evaluation activities show promise, but subsequent exploration drilling is not successful. (One could argue that this phase has already been completed once in both Poland and Germany, though it could be reinitiated again.)
- Large-scale development – initial exploration is successful, and the area of commercial viability is wide-spread (the overall area of the defined "sweet spot"), with subsequent development taking place over a wide area, with wells drilled over an extended number of years. This assumes that all of the wells estimated to correspond to the defined "sweet spot" in Poland and Germany are drilled, with commensurate production from these wells.
- Slow development – this case is the same as the large-scale development case, but the pace of development is only one-third of that in the large-scale case.
- Small-scale development – initial exploration is successful, but the area of commercial viability is small (considerably smaller than the initially defined "sweet spot"), with a relatively limited number of wells, for just a limited number of years. This case assumes that only about 20% to 25% of the wells estimated to correspond to the defined "sweet spot" in Poland and Germany are drilled and produced. In addition, substantially fewer exploration sites are pursued in this case.

These possible outcomes will be a function of success of exploration, economic prospectivity, forecast prices and market demand, the willingness of governments to allow development drilling to proceed, and, if pursued, the pace at which that development occurs. These phases/outcomes could be experienced just once, or could occur multiple times, as different prospects in different basins or plays are pursued.

These are discussed in more detail in the following pages.

Site Evaluation and Initial Exploration Phase

First 4 – 7 years. In the early stages in the pursuit of new UH resources in a play, where initial basin evaluation, leasing, asset evaluation, and exploration drilling takes place, most of the work will be either performed by international companies using expat employees, or by home office employees of Polish or German companies. Consequently, very few new local jobs are likely to be created in this phase of operations.

Specifically, the performance of the activities associated with the initial basin evaluation stage will be performed nearly exclusively by expat/home office employees, with the possible exception of drivers and interpreters assisting them in-country. Even in that case, an existing local driver or interpreter would be hired; no new jobs would likely be created for this activity. These activities would be applied to the basin as a whole.

Similarly, during the leasing phase, even though multiple sites within the basin may be considered, the personnel involved in this activity would be almost exclusively expat/ home office personnel, again with the possible exception of interpreters and drivers assisting them in-country. No new jobs would likely be created from this activity.

During the asset evaluation phase, the performance of the activities would still be mostly performed by expat/home office employees, again with the possible exception of drivers and interpreters assisting them in-country, and possibly, surveyors and their assistants that may be hired locally. Again, few new jobs would likely be created as a result of this activity. These activities would be applied to the basin as a whole.

If the results of the activities in the initial basin evaluation, leasing, asset evaluation stages conclude that the resource potential is non-commercial or its development is not permitted – consistent with the "quickly abandon exploration" success scenario – the resulting employment and other economic benefits associated with UH resource exploration activities would be minimal.

During the final exploration drilling phase, the job titles assigned to this activity in Table 19 of GIS specialist, environmental technician, geologist, geochemist, geophysicist, and geo tech are all likely to be performed by existing expat/home office personnel. These activities would not take place under a "quickly abandon exploration" scenario.

However, some of the jobs at this stage, should it be pursued, such as surveyor, surveyor's assistant, electronics technician, truck driver, heavy equipment operator, derrick hand, floor hand/roughneck/rig hand, mechanic, roustabout, and lease hand may be hired locally. In some cases, new jobs may be created for this activity. The extent that new jobs would get created would depend on how many individual sites are evaluated, how many of these are determined to be worthy of exploration drilling, how many exploration wells get drilled to evaluate each site deemed worthy of exploration, and over how many years this activity takes place.

During this exploration drilling phase, assuming that exploration proceeds, for purposes of this assessment, the following was assumed for the large-scale development case:

- Ten individual sites/assets are assessed in each basin considered.
- One individual site/asset evaluation is initiated per year, over 10 years*. In the slow development case, one individual evaluation is initiated every three years, over 30 years.*
- For each site/asset, 5 exploration wells are drilled, with one well drilled the first year, and two wells drilled in each of the next two years.
- An assumed €13,500,000 exploration well will result in 22 direct jobs during the period of exploration, of which, 75% are existing home office or expat personnel, and 25% are created locally over the period of exploration. Two indirect jobs are created for each direct job; 75% of the indirect jobs are assumed to be local.

- Three drilling crews are working continuously over the period of time where exploration is taking place, for all the sites in the basin.
- 25 jobs are associated with constructing the exploration drill site for each exploration well. 30 days are required for this site preparation.
- Salaries for those personnel hired locally at this stage will be on the lower end of the salary scale, since these will most likely be roustabouts, rig hands, and other personnel supporting geologists, engineers, and field supervisors supplied by the companies' home offices. All of these jobs are assumed to be local; with average wages for local site construction personnel of € 55 per hour.

In the small-scale development case, it is assumed that only 4 sites are evaluated, over 4 years.

Benefits from the Site Evaluation and Initial Exploration Phase. Under the large-scale development case, assuming activities are conducted at 10 potential drilling sites, over 10 years, a peak of 5 exploration wells will be drilled per year, at € 13,500,000 per well. At peak, this phase results in the following benefits for Germany or Poland:

- The creation of 110 direct jobs and 330 indirect jobs (440 total) associated with drilling, of which 193 are local jobs, and 247 are expat or home office jobs.
- The creation of 125 jobs, of which 94 are local jobs, associated with site construction.
- Expenditures on drilling and site construction peak at € 67.5 million per year
- The payment of € 37.6 million in salaries for the local jobs created.
- The collection of € 10.8 million annually in income taxes from salaried oil and gas field workers in Poland, and € 14.2 million annually in income taxes from comparable workers in Germany.

Under the smaller-scale development case, assuming activities are conducted at 4 potential drilling sites, over 4 years, the same peak levels of economic and employment benefits are realizable, but the period of time over which society benefits is much shorter.

Under the slow development scenario, activities are conducted at 10 potential drilling sites, over 30 years, with a peak of 2 exploration wells drilled in any year. At peak, this phase results in the following benefits for Germany or Poland:

- The creation of 44 direct jobs and 88 indirect jobs (132 total) associated with drilling, of which 77 are local jobs, and 165 are expat or home office jobs.
- The creation of up to 50 jobs, of which 38 are local jobs, associated with site construction.
- Expenditures on drilling and site construction peak at € 27 million per year
- The payment of up to € 13.5 million in salaries for the local jobs created.
- The collection of € 3.9 million annually in income taxes from salaried oil and gas field workers in Poland, and € 3.7 million annually in income taxes from comparable workers in Germany.

Development and Production Phase

This phase is characterized in two parts per site: (1) the next 5 - 15 years, after site evaluation and initial exploration, where facilities construction, development well drilling, completion and stimulation takes place; and (2) the subsequent 8 - 30 years, associated with the production from these wells. These two parts clearly overlap during this phase.

<u>Next 5 - 15 years</u>. This phase starts after the first 4 – 7 years of initial basin evaluation, leasing, asset evaluation, and exploration drilling has taken place. <u>This applies to the site or project as a whole, not to individual wells</u>. As described above, activities occurring during this phase include appraisal drilling, site preparation, development well drilling, hydraulic fracturing, well completion, and facilities construction. For site preparation and facilities construction, jobs are created on a site-specific basis, where job creation is based on the pace and level of well drilling.

On an individual well basis, well drilling activities are of limited duration, and represent a one-time, short term impact. However, when multiple wells are being drilled concurrently, and over a significant number of years, the economic and employment impact can be considerable, though specific economies-of-scale may reduce total job creation and the associated benefits derived from these jobs.

Eventually, most of the jobs necessary in performing these activities will be created locally, though it may take some time to evolve from expat or home office personnel to locals in the performance of some of the jobs.

During this development phase, *assuming that the basin/play proceeds to this phase*, for purposes of this assessment, the following was assumed:

- Development begins for each of the 10 individual sites/assets assessed in each basin considered, after the initial site evaluation process begins. That is, development begins for one new site/asset per year, over 10 years in the large-scale development scenario. One new site/asset every three years, over 30 years, is assumed in the slow development case
- Site preparation and facilities construction are assumed to take place in the first year. The jobs created during this phase are assumed to apply basin-wide, under the assumption that from one year to the next, the same personnel would bring their talents to each new site where development is initiated. Initially, the breakdown between local and expat/home office jobs is the same as during exploration drilling. However, after 10 years, 80% of these jobs are assumed to be local.
- During site preparation and facilities construction, 50 new jobs are assumed to be required for undertaking this activity. Initially, the breakdown between local and expat/home office jobs is the same as during the site evaluation and initial exploration phase. However, after 10 years, all of these jobs are assumed to be local.
- For each of the 10 sites/assets, it is assumed that one-tenth of the total number of wells required for the entire basin will be drilled at each site. Developmental drilling would begin in the second year, after site preparation and facilities construction are completed. These wells will be drilled over a period of 10 years. In total, it is initially assumed that up to 1,800 wells are drilled in Poland and 600 wells are drilled in Germany for the large-scale development scenario, and 400 wells are drilled in Poland and 200 wells are drilled in Germany for the small-scale development scenario.
- Three drilling crews are assumed to be working continuously over the period of time where development drilling is taking place at each location.
- Six development wells would be assumed to be drilled per crew per year; with three crews, 18 development wells would be drilled per site per year.
- Appraisal/development well drilling will result in 22 direct jobs, and 44 indirect and induced jobs for each well drilled. Initially, the breakdown between local and expat/home office jobs is the same as during exploration drilling. However, after 10 years, 80% of these jobs are assumed to be locally created jobs. These jobs are assumed to be associated with all activities involved in this phase.

- Salaries for local personnel directly associated with this development phase are assumed to be half higher-paid personnel (geologists, engineers, and field supervisors) and half lower paid personnel (roustabouts, rig hands, and other personnel supporting geologists, engineers, and field supervisors). For the indirect and induced jobs, 25% are assumed to be higher paid jobs, and 75% are assumed to be lower paid jobs.

Next 8 - 30 years. This phase starts after the first set of wells is drilled at a site, and is assumed to continue for 20 years. Since the statistics presented above are based on individual producing wells, the jobs-years required during this phase of operations are tied to the number of producing wells.

Based on the statistics presented above for job creation associated with producing oil and gas well on U.S. federal lands, it was assumed that each well is associated with 9 direct jobs-years, and 9 indirect and induced job-years. All of these jobs are assumed to be locally created jobs. These jobs are assumed to be associated with all activities involved in this phase.

Similar to that for development drilling, salaries for personnel directly associated with this phase are assumed to be half higher-paid personnel (geologists, engineers, and field supervisors) and half lower paid personnel (roustabouts, rig hands, and other personnel supporting geologists, engineers, and field supervisors). For the indirect and induced jobs, 25% are assumed to be higher paid jobs, and 75% are assumed to be lower paid jobs.

Benefits from the Development and Production Phase - Poland. For Poland, the benefits associated with the development and production phase were estimated based on the US-based cost assumptions summarized in Table 24. These costs were adjusted to be initially three times these costs, coming down over 10 years, to about 21% higher than costs based on US operations.

Table 24. Cost Assumptions for Estimating the Benefits Associated with the Development and Production Phase in Poland (US Based Costs)

	US Dollars	Euro
Cost per Development Well	$6,726,140	€ 6,053,526
Lease Equipment Cost per Well	$53,400	€ 48,060
Stimulation Costs per Well	$1,937,729	€ 1,743,956
Gathering System Cost per Well	$501,112	€ 451,001
OPEX per well	$34,500	€ 31,050
Gathering OPEX per well	$140,400	€ 126,360
Environmental Add on	$2,100	€ 1,890

Source: own elaborations on modelling results

Benefits are estimated based on the drilling of and production from 1,800 wells at 10 development sites. These wells are assumed to produce at gas production rates per well associated with the High EUR Case for Poland.

Highlights of the development, production, and associated employment and economic benefit associated with the large-scale development case are as follows:

- At full development, 1,800 wells are producing, with a peak production of 5.8 billion cubic meters per year. At peak, 180 wells per year are drilled in Poland.[7]
- Annual capital expenditures for development drilling and facility construction peak at nearly € 2 billion. As many as 9,700 local personnel are directly and indirectly employed in development drilling and facility construction activities.
- Annual operating expenditures grow to over € 340 million; as many as 32,400 local personnel are employed directly and indirectly in oil and gas field operations.
- As much as € 3.5 billion annually are earned in salaries by these personnel; for which they eventually pay as over € 1 billion annually in income taxes.
- Depending on prices, the industry can earn as much as € 1.9 billion to € 2.9 billion annually; the government could earn as much as € 29 to € 44 million annually in royalties.

Because of the likely marginally economic viability of these resources, government revenues from the special hydrocarbons tax and corporate income tax on oil and gas producers are forecast to be minimal.

These results are summarized for selected years in Table 25.

[7] Another recent report published by the EU-JRC assumed a peak of 213 wells per year (See Table 8 page 32 in (Lavalle, 2013)). Similarly, a recent report by the International Energy Agency (U.S. IEA, 2012) assumed that production from Poland could peak at a range of 14 to 30 Bcm per year (Figure 3.8, page 124), depending on the size of the resource base).

Table 25. Estimated Employment and Economic Benefits Associated with Large-Scale UH Development and Production in Poland

	2025	2030	2035	2040	2045	2050
No. of Producing Wells	180	810	1,530	1,800	1,800	1,800
Annual Gas Production (MMcf)	32,537	111,126	189,748	203,600	151,031	94,054
Annual Gas Production (million m^3)	922	3,150	5,378	5,771	4,281	2,666
Capital Expenditures (Million Euro)	€ 1,436	€ 1,894	€ 1,084	€ 181	€ 0	€ 0
Operating Expenditures (Million Euro)	€ 68	€ 180	€ 291	€ 343	€ 343	€ 343
Local Site Dev. & Drilling Personnel	3,407	9,670	6,653	1,109	0	0
Local Salaries for D&D Personnel (Million Euro)	€ 461	€ 1,038	€ 692	€ 115	€ 0	€ 0
Local Operating Personnel (Total)	3,240	14,580	27,540	32,400	32,400	32,400
Local Salaries for Oper. Personnel (1000 Euro)	€ 329	€ 1,478	€ 2,793	€ 3,285	€ 3,285	€ 3,285
Local Salaries for OPEX & CAPEX (1000 Euro)	€ 790	€ 2,516	€ 3,484	€ 3,401	€ 3,285	€ 3,285
Income Taxes on Local Personnel (1000 Euro)	€ 253	€ 805	€ 1,115	€ 1,088	€ 1,051	€ 1,051
Total Industry Revenues (million Euro)						
@ 332 Euro/cubic meter	€ 306	€ 1,046	€ 1,786	€ 1,916	€ 1,421	€ 885
@ 510 Euro/cubic meter	€ 470	€ 1,606	€ 2,743	€ 2,943	€ 2,183	€ 1,360
Revenues from Royalties (million Euro)						
@ 332 Euro/cubic meter	€ 5	€ 16	€ 27	€ 29	€ 21	€ 13
@ 510 Euro/cubic meter	€ 7	€ 24	€ 41	€ 44	€ 33	€ 20

Source: own elaborations on modelling results

Highlights of the development, production, and associated employment and economic benefit associated with the smaller-scale development case are as follows:

- At full development, 400 wells are producing, with a peak production of over 1.1 billion cubic meters per year.
- Annual capital expenditures for development drilling and facility construction peak at over € 420 million. About 2,200 local personnel are directly and indirectly employed in development drilling and facility construction activities.
- Annual operating expenditures reach € 76 million; with 7,200 local personnel directly and indirectly employed in oil and gas field operations.
- About € 780 million annually are earned in salaries by these personnel; for which they pay € 250 million annually in income taxes.
- Depending on prices, the industry can earn as much as € 380 to € 590 million annually; the government could earn € 6 to € 9 million annually in royalties.

These results are summarized for selected years in Table 26.

Table 26. Estimated Employment and Economic Benefits Associated with Small-Scale UH Development and Production in Poland

	2025	2030	2035	2040	2045	2050
No. of Producing Wells	40	180	340	400	400	400
Annual Gas Production (MMcf)	7,231	24,695	39,496	40,510	28,876	17,749
Annual Gas Production (million m^3)	205	700	1,119	1,148	818	503
Capital Expenditures (Million Euro)	€ 319	€ 421	€ 241	€ 40	€ 0	€ 0
Operating Expenditures (Million Euro)	€ 15	€ 40	€ 65	€ 76	€ 76	€ 76
Local Site Dev. & Drilling Personnel	789	2,186	1,478	246	0	0
Local Salaries for D&D Personnel (Million Euro)	€ 103	€ 231	€ 154	€ 26	€ 0	€ 0
Local Operating Personnel (Total)	720	3,240	6,120	7,200	7,200	7,200
Local Salaries for Oper. Personnel (1000 Euro)	€ 73	€ 329	€ 621	€ 730	€ 730	€ 730
Local Salaries for OPEX & CAPEX (1000 Euro)	€ 176	€ 559	€ 774	€ 756	€ 730	€ 730
Income Taxes on Local Personnel (1000 Euro)	€ 56	€ 179	€ 248	€ 242	€ 234	€ 234
Total Industry Revenues (million Euro)						
@ 332 Euro/cubic meter	€ 68	€ 232	€ 372	€ 381	€ 272	€ 167
@ 510 Euro/cubic meter	€ 105	€ 357	€ 571	€ 586	€ 417	€ 257
Revenues from Royalties (million Euro)						
@ 332 Euro/cubic meter	€ 1	€ 3	€ 6	€ 6	€ 4	€ 3
@ 510 Euro/cubic meter	€ 2	€ 5	€ 9	€ 9	€ 6	€ 4

Source: own elaborations on modelling results

Finally, highlights of the development, production, and associated employment and economic benefit associated with the slow development case are as follows:

- At full development, 1,530 wells are producing, with a peak production of almost 2.5 billion cubic meters per year
- Annual capital expenditures for development drilling and facility construction peak at nearly € 725 million. As many as 4,400 local personnel are directly and indirectly employed in development drilling and facility construction activities.
- Annual operating expenditures grow to over € 290 million; as many as 27,540 local personnel are employed directly and indirectly in oil and gas field operations.
- As much as € 3.1 billion annually are earned in salaries by these personnel; for which they eventually pay as over € 1 billion annually in income taxes.
- Depending on prices, the industry can earn as much as € 0.6 billion to € 0.9 billion annually; the government could earn as much as € 9 to € 14 million annually in royalties.

These results are summarized for selected years in Table 27.

Table 27. Estimated Employment and Economic Benefits Associated with Slow UH Development and Production in Poland

	2025	2030	2035	2040	2045	2050
No. of Producing Wells	90	324	630	936	1,224	1,530
Annual Gas Production (MMcf)	20,927	54,301	77,748	87,277	78,608	63,274
Annual Gas Production (million m^3)	593	1,539	2,204	2,474	2,228	1,793
Capital Expenditures (Million Euro)	€ 718	€ 631	€ 542	€ 723	€ 542	€ 542
Operating Expenditures (Million Euro)	€ 34	€ 72	€ 120	€ 178	€ 233	€ 291
Local Site Dev. & Drilling Personnel	1,724	3,255	3,326	4,435	3,326	3,326
Local Salaries for D&D Personnel (Million Euro)	€ 231	€ 346	€ 346	€ 461	€ 346	€ 346
Local Operating Personnel (Total)	1,620	5,832	11,340	16,848	22,032	27,540
Local Salaries for Oper. Personnel (1000 Euro)	€ 164	€ 591	€ 1,150	€ 1,708	€ 2,234	€ 2,793
Local Salaries for OPEX & CAPEX (1000 Euro)	€ 395	€ 937	€ 1,496	€ 2,170	€ 2,580	€ 3,139
Income Taxes on Local Personnel (1000 Euro)	€ 126	€ 300	€ 479	€ 694	€ 826	€ 1,004
Total Industry Revenues (million Euro)						
@ 332 Euro/cubic meter	€ 197	€ 511	€ 732	€ 821	€ 740	€ 595
@ 510 Euro/cubic meter	€ 303	€ 785	€ 1,124	€ 1,262	€ 1,136	€ 915
Revenues from Royalties (million Euro)						
@ 332 Euro/cubic meter	€ 3	€ 8	€ 11	€ 12	€ 11	€ 9
@ 510 Euro/cubic meter	€ 5	€ 12	€ 17	€ 19	€ 17	€ 14

Source: own elaborations on modelling results

Benefits from the Development and Production Phase -- Germany. For Germany, the benefits associated with the development and production phase were estimated based on the US-based cost assumptions summarized in Table 28. Like that for Poland, these costs were adjusted to be initially three times these costs, coming down over 10 years, to about 21% higher than US-based costs.

Table 28. Cost Assumptions for Estimating the Benefits Associated with the Development and Production Phase in Germany (US Based Costs)

	US Dollars	Euro
Cost per Development Well	$3,044,694	€ 2,740,225
Lease Equipment Cost per Well	$53,400	€ 48,060
Stimulation Costs per Well	$1,121,772	€ 1,009,595
Gathering System Cost per Well	$501,112	€ 451,001
OPEX per well	$32,500	€ 29,250
Gathering OPEX per well	$140,400	€ 126,360
Environmental Add on	$2,100	€ 1,890

Source: own elaborations on modelling results

Benefits are estimated based on the drilling of and production from 600 wells at 10 development sites for the large-scale scenario. These wells are assumed to produce at gas production rates per well associated with the High EUR Case for Germany.

Highlights of the development, production, and associated employment and economic benefit associated with the large-scale development case are as follows:

- At full development, 600 wells are producing, with a peak production of over 1.5 billion cubic meters per year. At peak, 60 wells per year are assumed to be drilled in Germany.[8]
- Annual capital expenditures for development drilling and facility construction peak at nearly € 325 million. As many as 3,300 local personnel are employed directly and indirectly in development drilling and facility construction activities.
- Annual operating expenditures grow to nearly € 115 million; 10,800 local personnel are directly and indirectly employed in oil and gas field operations.
- As much as € 1.2 billion annually are earned in salaries by these personnel; for which they eventually pay nearly € 490 million in income taxes.
- Depending on prices, the industry can earn as much as € 510 to € 780 million annually; the government could earn as much as € 150 to € 240 million annually in royalties.

These results are summarized for selected years in Table 29.

Table 29. Estimated Employment and Economic Benefits Associated with Large-scale UH Development and Production in Germany

	2025	2030	2035	2040	2045	2050
No. of Producing Wells	60	270	510	600	600	600
Annual Gas Production (MMcf)	7,463	27,547	49,634	54,126	40,154	25,006
Annual Gas Production (million m^3)	212	781	1,407	1,534	1,138	709
Capital Expenditures (Million Euro)	€ 245	€ 323	€ 185	€ 31	€ 0	€ 0
Operating Expenditures (Million Euro)	€ 22	€ 59	€ 96	€ 113	€ 113	€ 113
Local Site Dev. & Drilling Personnel	1,163	3,255	2,218	370	0	0
Local Salaries for D&D Personnel (Million Euro)	€ 154	€ 346	€ 231	€ 38	€ 0	€ 0
Local Operating Personnel (Total)	1,080	4,860	9,180	10,800	10,800	10,800
Local Salaries for Oper. Personnel (1000 Euro)	€ 110	€ 493	€ 931	€ 1,095	€ 1,095	€ 1,095
Local Salaries for OPEX & CAPEX (1000 Euro)	€ 263	€ 839	€ 1,161	€ 1,134	€ 1,095	€ 1,095
Income Taxes on Local Personnel (1000 Euro)	€ 111	€ 352	€ 488	€ 476	€ 460	€ 460
Total Industry Revenues (million Euro)						
@ 332 Euro/cubic meter	€ 70	€ 259	€ 467	€ 509	€ 378	€ 235
@ 510 Euro/cubic meter	€ 108	€ 398	€ 717	€ 782	€ 580	€ 361
Revenues from Royalties (million Euro)						
@ 332 Euro/cubic meter	€ 21	€ 78	€ 140	€ 153	€ 113	€ 71
@ 510 Euro/cubic meter	€ 32	€ 119	€ 215	€ 235	€ 174	€ 108

Source: own elaborations on modelling results

[8] Another recent report published by the EU-JRC assumed a peak of 486 wells per year. See Table 8 in (Lavalle, 2013).

Benefits for the small-scale development scenario for Germany are estimated based on the drilling of and production from 200 wells at 5 development sites. Highlights of the development, production, and associated employment and economic benefit associated with the large-scale development case are as follows:

- At full development, 200 wells are producing, with a peak production of nearly 0.7 billion cubic meters per year
- Capital expenditures for development drilling and facility construction peak at over € 160 million annually. Over 1,200 local personnel are employed in development drilling and facility construction activities directly and indirectly.
- Operating expenditures grow to € 38 million annually; as many as 3,600 local personnel are directly and indirectly employed in oil and gas field operations.
- As much as € 390 million annually are earned in salaries by these personnel; for which they eventually pay as over € 160 million annually in income taxes.
- Depending on prices, the industry can earn as much as € 230 to € 360 million annually; the government could earn as much as € 70 to € 110 million annually in royalties.

These results are summarized for selected years in Table 30.

Table 30. Estimated Employment and Economic Benefits Associated with Small-Scale UH Development and Production in Germany

	2025	2030	2035	2040	2045	2050
No. of Producing Wells	40	140	200	200	200	200
Annual Gas Production (MMcf)	4,975	16,701	24,622	21,475	13,771	8,335
Annual Gas Production (million m^3)	141	473	698	609	390	236
Capital Expenditures (Million Euro)	€ 163	€ 120	€ 21	€ 0	€ 0	€ 0
Operating Expenditures (Million Euro)	€ 15	€ 31	€ 38	€ 38	€ 38	€ 38
Local Site Dev. & Drilling Personnel	789	1,236	246	0	0	0
Local Salaries for D&D Personnel (Million Euro)	€ 103	€ 128	€ 26	€ 0	€ 0	€ 0
Local Operating Personnel (Total)	720	2,520	3,600	3,600	3,600	3,600
Local Salaries for Oper. Personnel (1000 Euro)	€ 73	€ 256	€ 365	€ 365	€ 365	€ 365
Local Salaries for OPEX & CAPEX (1000 Euro)	€ 176	€ 384	€ 391	€ 365	€ 365	€ 365
Income Taxes on Local Personnel (1000 Euro)	€ 74	€ 161	€ 164	€ 153	€ 153	€ 153
Total Industry Revenues (million Euro)						
@ 332 Euro/cubic meter	€ 47	€ 157	€ 232	€ 202	€ 130	€ 78
@ 510 Euro/cubic meter	€ 72	€ 241	€ 356	€ 310	€ 199	€ 120
Revenues from Royalties (million Euro)						
@ 332 Euro/cubic meter	€ 14	€ 47	€ 70	€ 61	€ 39	€ 24
@ 510 Euro/cubic meter	€ 22	€ 72	€ 107	€ 93	€ 60	€ 36

Source: own elaborations on modelling results

Finally, highlights of the development, production, and associated employment and economic benefit associated with the slow development case are as follows:

- At full development, 510 wells are producing, with a peak production of 0.65 billion cubic meters per year
- Annual capital expenditures for development drilling and facility construction peak at nearly € 123 million. As many as 1,500 local personnel are employed directly and indirectly in development drilling and facility construction activities.
- Annual operating expenditures grow to nearly € 96 million; 9,180 local personnel are eventually directly and indirectly employed in oil and gas field operations.
- Over € 1.0 billion annually are earned in salaries by these personnel; for which they eventually pay nearly € 440 million in income taxes.
- Depending on prices, the industry can earn as much as € 220 to € 340 million annually; the government could earn as much as € 70 to € 100 million annually in royalties.

These results are summarized for selected years in Table 31.

Table 31. Estimated Employment and Economic Benefits Associated with Slow UH Development and Production in Germany

	2025	2030	2035	2040	2045	2050
No. of Producing Wells	30	108	210	312	408	510
Annual Gas Production (MMcf)	4,972	13,489	20,313	23,202	20,899	16,822
Annual Gas Production (million m^3)	141	382	576	658	592	477
Capital Expenditures (Million Euro)	€ 123	€ 108	€ 93	€ 123	€ 93	€ 93
Operating Expenditures (Million Euro)	€ 11	€ 24	€ 40	€ 59	€ 77	€ 96
Local Site Dev. & Drilling Personnel	602	1,117	1,109	1,478	1,109	1,109
Local Salaries for D&D Personnel (Million Euro)	€ 77	€ 115	€ 115	€ 154	€ 115	€ 115
Local Operating Personnel (Total)	540	1,944	3,780	5,616	7,344	9,180
Local Salaries for Oper. Personnel (1000 Euro)	€ 55	€ 197	€ 383	€ 569	€ 745	€ 931
Local Salaries for OPEX & CAPEX (1000 Euro)	€ 132	€ 312	€ 499	€ 723	€ 860	€ 1,046
Income Taxes on Local Personnel (1000 Euro)	€ 55	€ 131	€ 209	€ 304	€ 361	€ 439
Total Industry Revenues (million Euro)						
@ 332 Euro/cubic meter	€ 47	€ 127	€ 191	€ 218	€ 197	€ 158
@ 510 Euro/cubic meter	€ 72	€ 195	€ 294	€ 335	€ 302	€ 243
Revenues from Royalties (million Euro)						
@ 332 Euro/cubic meter	€ 14	€ 38	€ 57	€ 66	€ 59	€ 47
@ 510 Euro/cubic meter	€ 22	€ 58	€ 88	€ 101	€ 91	€ 73

Source: own elaborations on modelling results

Last 2 – 8 years. In these final years, final decommissioning, site closure and remediation takes place. Site closure, remediation, and facilities decommissioning are assumed to take place in the final two years. The jobs performed during this phase are assumed to be a continuation of those for site prep and facilities construction, under the assumption that essentially the same skill set would be required for final site closure. During this final phase of activity, 25 jobs are assumed to be required.

However, in the time frame for this assessment, no sites are assumed to enter into finally decommissioning.

Labour Requirements and Other Economic Benefits – "Top Down" Assessment

In contrast to the "bottom up" assessment described in the previous section, an alternative method for estimating employment and other economic benefits is a "top down" approach.

A review of the job estimates generated by input-output models may shed some light on the order of magnitude of potential job creation that could be associated with new UH resource development. For example, a study of the economic and employment impacts associated with unconventional gas development in the US (IHS Inc., 2012) concluded that massive capital outlays, along with the promise of stable low natural gas prices, will have profound national economic consequences including:

- By 2015, the employment contributed by unconventional gas activity is projected to reach nearly 1.5 million US jobs on a path to more than 2.4 million jobs by 2035.
- By 2015, the annual contribution of unconventional gas activity to GDP is projected to reach nearly € 177 billion and, by 2035, is expected to more than double to nearly € 299 billion.

Simply put, these numbers show that approximately 700 to 800 jobs are created for each € 100 million in industry contribution (i.e., expenditures) to gross domestic product (GDP). Of these, in the producing states, 26% of these jobs were direct industry jobs, 31% were indirect jobs created, and 43% were induced by the increased economic activity generated by industry investment and direct and indirect employment.

On a more regional basis, a study of the economic impacts of oil and gas development on federal lands in the western US (SWCA Environmental Consultants, 2012) showed that the drilling of 3,164 wells would result in 120,905 jobs and $24.8 billion in economic activity, or about 487 jobs per € 100 million in industry expenditures.

On the more optimistic side, one study looking at the economic benefits of Marcellus shale gas development in the U.S. predicted € 3.49 billion of economic activity would contribute 44,098 jobs to the Pennsylvania economy, or over 1,264 jobs per € 100 million in industry expenditures (Considine , Watson, & Blumsa, 2010).

From the opposite corner of the globe, a study of the potential of oil and gas development in New Zealand (New Zealand Ministry of Business, Innovation, and Employment, 2013) examined several different scenarios relating to the scale of offshore oil and gas resource development. These scenarios ranged from average annual operating expenditures of NZ$ 110 million to NZ$ 2,300 million, and annual capital expenditures ranging from NZ$ 170 million to NZ$ 2,300 million (total annual expenditures of NZ$ 280 million to NZ$ 4,600 million). Depending on the case, these generated from 158 direct jobs in the small-scale scenario to 899 direct jobs in the most aggressive scenario. These result in estimates of jobs created per million NZ$ expended that are substantially less than those for the U.S. cited above, even accounting for the currency conversion.

An effort was made to compare "bottom up" and "top down" approaches for estimating employment benefits associated with new UH resource development and production. Two assumptions were made for estimating jobs as a function of expenditures: one assuming 500 jobs created per € 100 million of expenditures, and another assuming 900 jobs created per € 100 million of expenditures. This represents the range of estimates exhibited in much of the above discussion. In addition, two options were considered for characterizing expenditures; one assuming it applies only to capital expenditures, and the other assuming that it applies to both capital and operating expenditures.

The results of this comparison are presented in Table 32. As shown, the "bottom up" and "top down" approaches for estimating employment benefits are the same order of magnitude when applied to the earlier years of UH development and production, where activity if more focused on capital expenditures associated with well drilling. In the later years of new UH development and production, where activity is more focused on operating expenditures associated with previously drilled wells, the estimates from these two methods diverge substantially.

Table 32. Comparison of "Bottom Up" and "Top Down" Employment Benefits Associated with UH Development and Production in Poland and Germany

POLAND -- LARGE SCALE DEVELOPMENT						
Total Jobs -- Top Down (CapEx) Only	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
@500 jobs / 100 million Euro	7,178	9,468	5,421	903	0	0
@900 jobs / 100 million Euro	12,921	17,042	9,758	1,626	0	0
Total Jobs - Top Down (CapEx and OpEx)						
@500 jobs / 100 million Euro	7,519	10,366	6,878	2,618	1,714	1,714
@900 jobs / 100 million Euro	13,534	18,659	12,380	4,712	3,086	3,086
Total Jobs - Bottom Up	**6,647**	**24,250**	**34,193**	**33,509**	**32,400**	**32,400**
POLAND -- SMALL SCALE DEVELOPMENT						
Total Jobs -- Top Down (CapEx) Only	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
@500 jobs / 100 million Euro	1,595	2,104	1,205	201	0	0
@900 jobs / 100 million Euro	2,871	3,787	2,168	361	0	0
Total Jobs - Top Down (CapEx and OpEx)						
@500 jobs / 100 million Euro	1,671	2,304	1,528	582	381	381
@900 jobs / 100 million Euro	3,007	4,146	2,751	1,047	686	686
Total Jobs - Bottom Up	**1,509**	**5,426**	**7,598**	**7,446**	**7,200**	**7,200**
GERMANY -- LARGE SCALE DEVELOPMENT						
Total Jobs -- Top Down (CapEx) Only	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
@500 jobs / 100 million Euro	1,225	1,616	925	154	0	0
@900 jobs / 100 million Euro	2,206	2,909	1,666	278	0	0
Total Jobs - Top Down (CapEx and OpEx)						
@500 jobs / 100 million Euro	1,338	1,912	1,406	719	565	565
@900 jobs / 100 million Euro	2,408	3,442	2,530	1,294	1,017	1,017
Total Jobs - Bottom Up	**2,243**	**8,115**	**11,398**	**11,170**	**10,800**	**10,800**
GERMANY -- SMALL SCALE DEVELOPMENT						
Total Jobs -- Top Down (CapEx) Only	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**
@500 jobs / 100 million Euro	817	599	103	0	0	0
@900 jobs / 100 million Euro	1,470	1,078	185	0	0	0
Total Jobs - Top Down (CapEx and OpEx)						
@500 jobs / 100 million Euro	892	752	291	188	188	188
@900 jobs / 100 million Euro	1,605	1,354	524	339	339	339
Total Jobs - Bottom Up	**1,509**	**3,756**	**3,846**	**3,600**	**3,600**	**3,600**

Source: own elaborations on modelling results

For comparison purposes, with regard to employment forecasts associated with new UH resource development in Europe, the International Association of Oil and Gas Producers (OGP) commissioned to Pöyry Management Consulting and Cambridge Econometrics (CE) to examine the impact of potential shale gas production on energy prices and macroeconomic indicators for the EU28 countries for the period 2020 to 2050 (Pöyry Management Consulting and Cambridge Econometrics, 2013). This study analysed a range of potential shale gas scenarios from 'No Shale' to 'Some Shale' to 'Shale Boom' production levels in the EU. The "Some Shale" Scenario assumes 15% of the risked resources in place are technically recoverable and represents a projection of shale gas production with sufficient levels of political and public support to enable developments to proceed. The "Shale Boom" Scenario is a more optimistic projection of shale gas production that assumes 20% of the risked resources in place are technically recoverable and is based on the assumption that widespread public and political support can be achieved and that any barriers to production are minimized. In order to achieve the level of production shown in the Shale Boom Scenario, they estimated that between 33,500 and 67,000 wells (depending on well productivity) will need to be drilled by 2050 in the entire EU.

The study examined the impact of potential shale gas production on energy prices and macroeconomic indicators. For increases in production for all of Europe ranging from 80 to 180 billion cubic meters per year, more than an order of magnitude larger than that assumed in this study. In the Some Shale Scenario EU28 GDP increases by € 57 billion (0.3% increase) and € 138 billion (0.6% increase) in 2035 and 2050 respectively. In the Shale Boom Scenario, GDP increases by € 145 billion (0.8% increase) in 2035 and € 235 billion (1.0% increase) in 2050.

In terms of employment impact, in the Some Shale Scenario, net employment increases by 400,000 by 2035 and 600,00 by 2050 were forecast. In the Shale Boom Scenario, net employment increases by 800,000 jobs by 2035 and 1.1 million jobs by 2050 were forecast. Dividing jobs created by the increase in GDP provides employment ratios of approximately 450 to 700 jobs created per € 100 million increase in GDP (which includes more than just expenditures for oil and gas development and production.

Finally, a report by the International Agency forecast total production from Europe in their optimistic "Golden Rules" case to peak at 77 Bcm per year, over ten times that assumed for Germany and Poland in this study (World Energy Outlook, 2012).

Other Potential Economic Benefits Not Considered

In this study, the economic benefits associated with ne UH resource development focused on the investment impacts and government revenues. Impacts such as that on Gross Domestic Product (GDP), energy import dependency, and energy prices (oil, gas, and electricity) were beyond the scope of this effort.

In Poland, the potential annual incremental production associated with new large-scale UH development and production peaks at about 5.8 billion cubic meters (182 Bcf) in 2040. This represents about 39% of the total annual consumption in 2014 of about 14.65 billion cubic meters. This could have an impact on the natural gas import dependency in Poland, and could affect both natural gas prices and electric power prices (should natural gas significantly displace coal consumption in power generation).

In Germany, on the other hand, the potential annual incremental production associated with new large-scale UH development and production peaks at over 1.5 billion cubic meters (54 Bcf) in 2040. This represents only about 2% to 3% of the total annual consumption in 2014 of about 63.84 billion cubic meters. This would likely not greatly impact either natural gas import dependency or energy prices in Germany.

The study by Pöyry and CE for ODP examined the impact of potential shale gas production on energy prices and macroeconomic indicators. For increases in production for all of Europe ranging from 80 to 180 billion cubic meters per year, more than an order of magnitude larger than that assumed in this study, wholesale natural gas prices declined by 6% to 14%, and wholesale electricity prices declined by 3% to 8%.

Similarly, (Kurt, 2013) also examined several scenarios for shale gas development in Europe. Under their most optimistic scenario, annual shale gas production in all of Europe reaches nearly 60 billion cubic meters, or about 10% of total consumption in Europe. They forecast a relative reduction in gas trading prices of 2% to 6% of the gas price expected for 2035. As many as 255,000 new jobs would be created as a result, according to this study.

Finally, a study by (ICF GHK, 2014) assessed the macro-economic impacts of shale gas development under a base case scenario as well as two alternative policy scenarios to manage environmental risk. In these scenarios, UH production grows to levels ranging from 20 Bcm to 130 Bcm per year, depending on the scenario. The report summarizes the proportional changes in impacts such as GDP, employment, imports, exports, etc., relative to the base case, but does not provide absolute values of these impacts.

Regulatory Issues and Public Finance

To date, the results of exploration for shale gas resources in Poland and Germany have been disappointing, though other unconventional hydrocarbons, such as CBM in Poland and tight gas in Germany, have been historically pursued. For shale, initial production rates were low, and reservoir conditions associated with these wells were determined to be generally unfavourable. Moreover, in both countries, while prospection and exploration concessions have been granted for UH resources, no development/production concessions have yet been granted.

Disappointing resource characteristics along with, some believe, the lack of adequate incentives to stimulate new UH (particularly shale gas) resource development, has led a number of multinational companies to curb their enthusiasm for further pursuits in Poland and Germany (Strzelecki, 2012). More recently, even state-run firms in Poland – PGNiG and PKN Orlen – are ending their shale gas pursuits (Rigzone, 2016).

However, as described previously, based on the North American experience, new shale-focused exploration drilling to date in Europe has probably not been sufficient to locate potential geologic "sweet spots" and optimize well drilling and completion design.

Moreover, this analysis shows that even the resources characterized as being in potential "sweet spots" in Poland and Germany are likely to be marginally economic at best, at least initially, assuming the Most Likely Case EUR. And this "sweet spot" was defined only in the one play in each country that would most likely to be commercial.

Given the marginal economics, government policies that impact project timing and/or project costs are of critical importance, since they can substantially enhance or inhibit the exploration and ultimate development of new UH resources.

New UH resource development in EU Member states, including Poland and Germany, are subject to both national and EU-level legislation, regulation and processes and practices of oversight organizations. These could either encourage or inhibit new UH resource development. Therefore, it is important to understand how these may impact development, especially given the conditions and resource characteristics in Poland and Germany, if any economic and employment benefits from UH resource development can be realized.

There are two categories of potential challenges to new UH resource exploration and development. Both can add to development and production costs, and adversely affect commercial viability.

The first category relates to the concession terms and the sharing of the proceeds of new UH resource development and production with the government. Government treasuries need to obtain a "fair rent" for granting the concessions, and has the necessary financial resources to oversee these activities. However, too much "sharing" may stifle project development. This is the primary category for consideration in this report.

The second category of challenges is generally related to the requirements and associated costs for addressing environmental concerns. In some cases, addressing environmental concerns add to costs; though in other cases, environmental measures could in fact provide economic benefits (U.S. EPA, 2012).

Consideration of this category of potential challenges is beyond the scope of this report.

Therefore, this final section of this report aims to focus on regulatory and fiscal aspects associated with the development of new UH resources. For both Poland and Germany, this includes an overview of:

- The allocation of rights for exploration and development, with an explanation of the possible concessionary or contractual systems in force.
- The implications of fiscal settings for the cost structure of projects (royalties, corporate tax rates, etc.).

- Insights on the effects that the fiscal regime has on the oil/gas output, including the extent to which the fiscal regime can reduce the pursuit of marginal fields, and a characterization in terms of stability, flexibility or neutrality of the different fiscal instruments actually in force.

Allocation of Rights for Exploration and Development

Poland. Regulations used during the prospecting, exploration and production of UH resources in Poland, as well as administrative decisions and permissions that must be obtained, are regulated by various laws. Exploration, documentation and development of UH resources is primarily regulated by the Geological and Mining Law and the regulations of the Minister of the Environment (Uliasz-Misiak , Przybycin, & Winid, 2014). Hydrocarbon deposits are part of the mining property owned by the State Treasury.

Since the idea of UH prospecting/exploration and production is relatively new, the legislation originally in place in Poland did not fully respond to the special circumstances associated with UH resources. UH prospecting/exploration and production were covered by laws applicable to other hydrocarbons. Until 1 January 2012, UH prospecting/ exploration and production was regulated under the Geological and Mining Law of 4 February 1994 (Geological and Mining Law, 1994). On 1 January 2012, that law was replaced with the Geological and Mining Law of 9 June 2011 (Geological and Mining Law, 2011).

Initially, the E&P companies operating or hoping to operate in Poland were concerned whether the new regulations would simplify procedures and shorten the waiting time for obtaining decisions from government administrators. Historically, separate concessions were issued in Poland – one for prospecting, one for exploration, and one for development and production. In order to encourage investors to search for oil and gas, including UH resources, proposed amendments to the Geological and Mining Law were submitted for public and inter-ministerial consultations in February 2013. Changes regarding the abolition of licenses for UH, simplification of investment procedures, and a more competitive tax system were proposed with the intent of stimulating the oil and gas sector.

One of the biggest changes proposed combined concessions for both documentation and exploration of hydrocarbons, and subsequent development. This provision ensured that meeting the obligations required to obtain the license already at the stage of documentation gives the exclusive right for extracting hydrocarbons. An 'investment decision' will be required to move from the exploration to the production phase.

Despite these proposed changes, concerns remained. The position of the licensing authority was significantly strengthened, with the intent of providing an effective tool to enforce the obligations under the concession. Moreover, the proposed legislation would have established a specific mining and hydrocarbon regulator, NOKE (Narodowy Operator Kopalin Energetycznych) to oversee the companies involved in the production of oil and gas in Poland. Companies would have been obliged to contact the NOKE, which would have participated in the extraction process on behalf of the state treasury. Cooperation between the company and the NOKE, some believed, could have had a significant impact on the pace of investment. At the same time, NOKE would have supported entrepreneurs in obtaining all necessary permits and – to some extent – possibly bear some investment risk.

In addition, financial aspects were of particular interest by stakeholders, especially when it came to the proposed increase of fees. Their concern was that these fees, combined with new taxes on hydrocarbons, could cause marginal prospects to be unprofitable.

In March 2013, the Polish government proposed new draft legislation believed to be more attractive for investors, in response to the initial criticism. The legislation proposed that taxes on shale gas extraction will not be imposed until 2020, and after 2020, new tax rates would not exceed 40% of the profit arising from extraction, on a sliding scale. The plans to create a state-owned operator (NOKE) were withdrawn, and license procedures were further simplified and accelerated.

In May 2014, yet another proposed amendment to Mining and Geological Law was proposed and debated in Parliament (Dobrowolsk & Pichet, 2014). The proposal still maintained the concept of a single concession, to be awarded for a fixed term, but extended the term of the concession to not shorter than 10 years and not longer than 30 years -- to a winning single bidder or a bidding consortium (previously, the various concessions are granted for periods between three and 50 years). The concession would be divided into two stages -- a prospecting and exploration stage; and a production stage. The proposed amendments would also facilitate the geophysical surveys of hydrocarbons by requiring that they be subject only to a notification rather than to a prior authorization requirement.

The idea of establishing NOKE remained withdrawn. Instead of NOKE, the Bill introduced several levels and instruments of State control over the process before and during the concession (e.g., prequalification, triggers for concession expiration and withdrawal). In addition, marginal reservoirs were defined for which no service charge is planned.

Other proposed amendments would also simplify the environmental assessment process and move the timing of the assessments from the beginning of the investment process to a stage just before the drilling commences. However, in April 2016, the European Commission referred Poland to the Court of Justice of the EU for failing to ensure that the environmental impacts of UH resource development are properly assessed, and that national legislation should not be changed to such an extent that it is in non-compliance with EU law (European Commission, 2016) and (Tarka , 2015).

Finally, the proposed amendments drop the Government's earlier proposal to establish a state-run fund that would have held a stake in shale gas concessions and that shale gas companies criticized for being overly bureaucratic.

Additional legislation is under consideration to simplify administrative and legal procedures and to increase their clarity even more. In response to investors' concerns, the intent is to bring together in a single legal act provisions concerning the preparation and execution of hydrocarbon production, thus encouraging them to implement investment projects. This could involve: (1) shortening the waiting time for decisions on environmental conditions for the project implementation, decisions on reclassification of land as non-agricultural land, decisions on temporary reclassification of land as non-agricultural or non-forest land; (2) faster issuance of permits required under the Water Law Act; and (3) eliminate lengthy procedures relating to obtaining a legal title to real property for conducting the authorized operations.

Germany. Mining legislation in Germany consists of the Federal Mining Act from 1980 and a number of Mining Ordinances on technical and procedural issues. These provisions are applicable to the exploration and exploitation of most mineral resources in Germany, including hydrocarbons. The Federal Mining Act (article 3 par. 2 Federal Mining Act) differentiates between mineral resources that are part of landed property on the surface and others that are not. Hydrocarbons are not considered landed property under the Act (Grit, 2012). No distinctive process exists for oil and gas, nor for UH resources.

The Act provides for a tiered procedure in the approval of projects. First, it distinguishes between exploration and extraction. In both of these two stages it differentiates between the granting of a license and the approval of activities through operational plans. The first step of the tiered approval procedure is to apply for an exploration license. The Act distinguishes between three types of license: a concession, which grants the right to explore; a permission conferring the right to explore and to extract; and a special form of permission, which opens up the possibility to secure the right to explore and extract by making an entry into the land register.

Upon granting the license, the mining authority makes a binding decision. The license has to be conceded unless one or more of the conditions listed in article 11 of the Federal

Mining Act are fulfilled. The provision does not mention environmental aspects explicitly, but these may be included in the decision. The license has to be denied if "predominant public interests" preclude the exploration/extraction in the entire claim to be allocated. According to article 15 of the Act, the mining authority must consult the authorities safeguarding public interests before deciding on an application for an exploration license.

The second step in the tiered authorization procedure is the operational plan developed by the mining company, which needs to be approved. The Act lists four types of operational plans: the principal operational plan, the framework operational plan, the operational plan for special issues, and the operational plan for closure.

One critique of the present legal framework is that neither the public nor stakeholders (except for the authorities and the municipalities regarding aspects of urban development) need to be consulted in the procedure of granting a concession for exploration and/or extraction.

In Germany, current shale gas projects involving hydraulic fracturing are still in the exploration phase. For these projects, only a license for exploration has been granted; in some cases, operational plans for exploration have been approved and exploration commenced. Licenses for extraction have not yet been issued. Moreover, the German government DE decided in 2016 to prohibit hydraulic fracturing in shale, clay, marl and coal seam rocks, except for up to four tests which could be allowed for scientific purposes (The Guardian, 2016).

Fiscal Settings for the Cost Structure of UH Projects

In response to the potential of new UH resource development in EU Member states, fiscal regimes are being modified for two main reasons:

- To better manage the wealth that might be derived by future UH production (as in the Danish and Polish cases).
- To attract the investment required by UH resource development (as sought by the UK).

Without doubt, the state treasury requires a fair share of the economic rewards associated with granting the concessions for UH resource exploration, development, and production. Moreover, the government requires the necessary financial resources to oversee its activities. On the other hand, if the UH resources never get developed, then neither producers or governments benefit. Therefore, balancing these two objectives is necessary to ensure that the economic benefits desired from UH resource development are realizable.

Poland. As described previously, new fiscal requirements in Poland represent a two-fold increase in the tax burden for oil and gas producers in Poland, which, due to historical reasons, previously were subjected to a relatively low tax burden (Uliasz-Misiak , Przybycin, & Winid, 2014).[9]

This regime was implemented to establish a preferential tax regime for fossil fuels, including shale gas. The Polish Ministry of Finance estimates that the proposal would bring the overall tax burden imposed on companies engaged in the shale gas production and other hydrocarbon production activities in Poland to around 40%. (In contrast, recent reforms in the UK envision lowering the tax rate for UH resource development from 62% to 30%.)

In particular, tax obligations in Poland include: (1) an *ad valorem* tax on the extraction of certain minerals, and (2) a Special Hydrocarbon Tax (SHT). The *ad valorem* tax rate

[9] For the most part, in Poland, the fiscal framework was not structured for taking profits from oil and gas production, since the country already benefitted from the stakes in PGNiG, the state-owned company. For example, royalties did not exist before 2011.

varies according to the hydrocarbon type: 3% on conventional gas, 1.5% on unconventional gas; 6% on conventional oil, and 3% on unconventional oil.

The SHT rate ranges between 0% and 25% depending on the ratio of revenue earned to expenditure incurred. The tax rate amounts to 12.5% when the ratio of revenues to expenditure is between 1 and 2; and 25% when the ratio of revenues to expenditure is equal to or greater than 2. Where the ratio of revenues to expenditure is below 1, the SHT rate is 0%.

Pursuant to the proposed rules, companies would be required to declare their profits, as well as their expenditure and revenue, via electronic declarations. In addition, they would need to make monthly tax deposits to the Polish tax authorities.

Finally, in order to stimulate short-term investments in shale gas operations, the new tax rates do not apply until 2020.

Germany. As described earlier in this report, the fiscal regime that applies to the oil and gas industry in Germany consists of a combination of royalties and corporate profits tax, i.e. corporate income tax, solidarity surcharge and trade tax. In principle, there is no special taxation regime applicable to the oil and gas industry in Germany; nor has any special fiscal regime been established for UH resource development and production.

The overall combined corporate profits tax rate amounts ranges from 22.8% up to 34% (with an average of 29.8%, which is assumed in this report). Royalties are imposed annually at individual state level and can vary between rates of 0% and 40% based on the market value of the produced oil or gas at the time of the production. The royalties can be deducted from the tax base for German corporate income tax and trade tax purposes.

This fiscal regime, relative to others in the EU to promote new UH resource development and production may inhibit such development given the marginal economic viability anticipated for UH resources in Germany.

Effects of Fiscal Regime on Oil/Gas Output

Because of the likely marginally economic viability of new UH resources in Poland and Germany, government revenues from the special hydrocarbons tax and corporate income tax on oil and gas producers are forecast to be minimal. However, the impacts of royalties, and project timing, can be quite important.

In the case of Poland, the oil and gas tax regime has been modified for UH resource development to encourage investment, with the government gaining most of its financial benefits when projects are sufficiently profitable. The SHT is structured such that it is applied at its maximum rate only when revenues sufficiently exceed expenses, so income taxes only apply when an operator is in fact generating positive cash flow.

Germany, on the other hand, imposes high royalties, such that the government takes its share "off the top," regardless of whether or not positive cash flow is being realized by the operator.

Conclusions

The aim of this study has been to assess the potential impacts of new UH resource development and production in Poland and Germany. If these levels of production shown can be achieved, then the energy markets and the economies of these two countries should see significant benefits.

However, the achievement of these levels of production will require further exploration and appraisal of the shale resources, substantially improved efficiencies and lower development and production costs, the development of an onshore rig manufacturing and drilling industry and both political and public support. While a US-style increase in domestic gas production and reduction in natural gas prices is not expected, the production of UH resources could result in the creation of new jobs in the oil and gas sector, new government revenues, increased economic activity, and, possibly, wholesale energy prices that would be lower than they otherwise would have been.

The production scenarios in this study have been developed based on the best resource information available at the time and on information from the North American experience. However, it should be recognized that the present time, no shale gas resources are being produced, and accordingly limited information on the characteristics of the resource, its production potential, and the costs of its pursuit is available. As better information should become available as more test wells are drilled, such estimates of benefits can be further refined.

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List of abbreviations and definitions

AAPG	American Association of Petroleum Geologists
AFE	Authorizations for Expenditure
Bcf	billion cubic feet
Bcfd	billion cubic feet per day
Bcm	billion cubic meters
BGR	German Federal Institute for Geosciences and Natural Resources
Btu	British thermal unit
CAPEX	capital expenditures
CBM	Coalbed methane
CE	Cambridge Econometrics
CIT	Corporate Income Tax
DJ	Denver-Julesburg
E&P	exploration and production
EIA	Environmental Impact Assessment
EC	European Commission
EU	European Union
EUR	Estimated ultimate recovery
GDP	Gross Domestic Product
GRI	Gas Research Institute
IEA GHG	IEA Greenhouse Gas R&D Programme
IP	Initial productivity
JRC-IET	Joint Research Centre – Institute for Energy Transport
km^2	square kilometer
kPa	kilopascal
Kwh	kilowatt-hour
M	meter
MAC	marginal abatement cost
Mcm	million cubic meters
MMBtu	million Btu
MMcfd	Million Cubic Feet per Day
NE PA	Northeast Pennsylvania
NOKE	Narodowy Operator Kopalin Energetycznych
NSPS	New Source Performance Standards
NZ	New Zealand
OGP	Oil and Gas Producers
OPEX	operating expenditures
PGS	Polish Geological Survey
Psi	pound per square inch
REC	reduced emissions completions
Ro	thermal maturity
SEC	Securities and Exchange Commission
SHT	Special Hydrocarbons Tax
SPE	Society of Petroleum Engineers
SW PA	Southwest Pennsylvania
Tcf	trillion cubic feet
TD	total depth
TOC	total organic content
TSD	Technical Support Document
UH	Unconventional hydrocarbons
US	United States
USD	US Dollar
U.S. EIA	U.S. Energy Information Administration
USGS	US Geological Survey
VOCs	volatile organic compounds

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Annexes

Annex 1. APPROACH USED IN THE STUDY

METHODOLOGY

Critical considerations for characterizing potential benefits in this study included:

- Cost and resource deployment estimates that are specifically tied to the resource characteristics in Poland and Germany, as best those are known at this time.
- UH Shale gas (?) resource productivity and economics that account for increased resource understanding, technology evolution, and improvements in efficiency that takes place over time and as development in a play evolves
- Benefits characterizations that are performed at two points in the maturity of a shale gas n UH(?) resource play: when exploration, development, and production initiates (with mostly non-local personnel); and as development in the play matures (with most personnel locally based).
- The incorporation of best environmental practices, and their corresponding costs, in the assessment.

At the heart of the debate about the future outlook for UH resources in Europe, consistent with that which has taken place in North America, is the pace and ability to find the most productive areas of a play – the so-call "sweet spots," which often represent a very small portion of the total area of a play. The report concludes that exploration for UH resources in Europe, based on the historical experience in North America, may not yet be sufficient for identifying such "sweet spots."

In this study, the following steps were pursued for potential UH resources in Poland and Germany:

- Based on the resource characteristics, as currently understood, of the UH plays in each country, a potential future "sweet spot" with modest productivity was posited in a potential "yet be discovered" region as a result of future exploration drilling.
- Given these characteristics, and based on analogies from producing UH basins in North America, estimated ultimate recovery (EURs) values for fractured horizontal oil and/or gas wells for a Base Case (most likely), Low and High Case were developed.
- A cost model based on unpublished and proprietary work for the US Energy Information Administration (U.S. EIA), along with a proprietary project-specific economic model, was used to assess the potential commercial viability of UH resource development.
- For a portion of the Shale gas (?) UH resource potential assumed to be commercially viable – the so-called "sweet spot" – in Poland and Germany, a "bottom up" approach, accounting for the distinct phases of UH development and production, the investment required in each phase of activity, and the personnel (both local and non-local) required for each phase, was used to estimate selected potential economic and employment benefits associated with development and production of UH resources from the "sweet spot" in each country.

Provided that estimates of potential shale gas (?)UH production can be developed, based either on well performance, specific resource characteristics, or by analogy to other producing shale (?)UH plays, the analytical methodology can be standardized and used for other case studies in other UH resource settings.

DATA

Most of the sources of the sources of data/information used or referenced in this study come from technical reports by public institutions, or are otherwise generally accessible. In many cases, the web sites for which this data/information can be accessed are provided in the references. A few references are from sources only accessible with a subscription, or can be accessed for a relatively modest cost.

There are two exceptions to this:

- The cost model used in this study for assessing the commercial viability of UH resource development in Europe is based on unpublished and proprietary work for U.S. EIA. The objective of this work was to develop a component-based cost model for use by U.S. EIA to assess the commercial viability of shale gas development in various areas around the world. However, in this report, sufficient information based on this cost model has been provided to allow for the development of an independent cost model applicable for the EU.
- The assessments of the commercial viability of UH resources in Poland and Germany were performed using Advanced Resources' proprietary costing and economics model. However, given that all of the key inputs and assumptions pertaining to the economic modelling have been provided -- such as oil and natural gas prices; assumed rates for royalties, *ad valorem* taxes, and income taxes; capital expenditures (CAPEX) and operating expenditures (OPEX) -- any standard cash flow model for oil and gas production could be used to duplicate these analyses.

RESULTS

The objective of this effort, as originally stated, was as follows:

"The purpose of this effort is to provide the JRC-IET with a comprehensive overview of the potential impacts of exploration and exploitation of unconventional gas and oil in Europe. The countries selected as the focus of this initial effort are POLAND and GERMANY."

This assessment concluded that, in both countries, commercial viability would likely not be achievable unless estimates of ultimate recovery (EURs) approach the high end of potential productivity that is assumed to be realizable, or resource development costs and/or government royalties are significantly reduced, and only in areas defined as the "sweet spots."

Economic and employment benefits for UH resource development and production were estimated for two phases of activity: (1) a site evaluation and initial exploration phase, and (2) (if pursued) a development and production phase.

The benefits estimated included the jobs likely to be created in the exploration, development, and production of UH resources in Poland and Germany, the expenditures (capital and operating) estimated to be made in this pursuit, and the revenues collected by governments from both oil and/or gas production and the taxes on salaries for personnel involved in this pursuit.

Based on this, the assessment reviewed the fiscal regimes in both countries. In Poland, it was concluded that oil and gas tax regime has been modified for UH resource development to encourage investment, with the government gaining most of its financial benefits when projects are sufficient profitable. Poland's Special Hydrocarbons Tax (SHT) is structured such that its applies at its maximum rate only when revenues sufficiently exceed expenses, and income taxes only apply if an operator is in fact generating positive cash flow.

In Germany, on the other hand, since that the government takes its share "off the top," regardless of whether or not positive cash flow is being realized by the operator, it was concluded that this potentially could stifle investment.

Thus, the results of this assessment effectively and appropriately address the initial questions posed, and are useful to understand the phenomenon under investigation. Also, where applicable, the results are comparable to the results of other studies of the same type, thought the benefits estimates in this assessment tend to be less optimistic that those obtained from other studies.

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