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ABSTRACT

Since fossil fuel subsidies entail significant economic, fiscal, social and environmental costs, more and more attention is being paid to phasing out fossil fuel subsidies. The OECD has recently completed a report quantifying the amount of both producer and consumer subsidies for their member countries, and some work has been implemented on analyzing the effects of consumer subsidy removal. However, there is hardly any investigation of the consequences of producer subsidies. In this paper, we focus on oil and gas producer subsidies of OECD countries and their effects. First, we describe the transfer mechanisms indicated by the OECD report for producer subsidies. In order to recommend models to analyze the influence of removing producer subsidies, we review upstream oil and gas models and provide a taxonomy for them. From them we recommend the most appropriate models for each type of producer subsidy to model upstream decision making. Our contribution in this paper is to categorize the upstream models we have found, compare their main features, as well as recommending best in class models for analyzing the effects of each type of upstream producer subsidy.

JEL **classifications: H2, L71, Q38, Q41**
Keywords: Producer subsidy, upstream oil and natural gas models, model recommendation, survey.

1. Introduction

In 2009, the G20 and APEC countries made commitments to phase out fossil fuel subsidies [1]. As economists are well aware, such subsidies may drain the public coffers and are often inefficient from a social point of view. In order to evaluate the effect of these subsidies, we initially need to understand the magnitudes and mechanisms of these subsidies. To address this first step, the OECD has completed their first comprehensive inventory of estimated budgetary support and tax expenditures of fossil fuels for the 34 OECD member countries [1].

The OECD estimates that fossil subsidies may total as high as 50-90 billion U.S. dollars (USD) annually from 2005-10 for these countries [2]. Some of these subsidies are given to consumers, some to producers, and some to what the OECD calls general services. This latter category includes subsidies that do not influence current production or consumption such as compensation for past environmental damage, R&D, and strategic stockpiles.

Although consumer energy subsidies have received a considerable amount of study (see for example IEA [3]), a unique feature of this latest OECD undertaking is that it also catalogues and measures producer subsidies. A difficulty in measuring producer subsidies is that many of the subsidies are indirect. However, the OECD heroically categorizes and estimates magnitudes for this latter category as well. The support to producers for OECD countries was about 18 billion USD in 2011 (22% of the total). The support to consumers totaled 62 billion USD (75% of the total) while the rest is for general services. Although such subsides may help certain sectors of the economy, they may be detrimental to combined welfare and may degrade the environment for current and future generations. Thus, the removal of such subsidies should have positive fiscal results, improve the environment, as well as improve overall social welfare. Although many have considered consumer subsidies [4], to our knowledge no one has modeled the effects of producer subsidies. Our contribution in this paper is to consider these various producer subsidies and catalogue models that might be used to analyze the effects of these subsidies.

In section 2, we set the context for our analysis on a country by country basis by outlining the subsidies. Subsidy type, context and question asked will set the framework for the type of model to apply. In section 3, we develop a taxonomy for the models we have found and use it to catalogue the existing fleet of upstream oil and gas supply models that we consider for upstream subsidy analysis. In the final task, we analyze the transfer paths of producer subsidies for OECD countries, and recommend appropriate models for each type to reflect the impacts of subsidy removal on these upstream variables.

2. Producer Subsidies by OECD Countries

This section puts the producer energy subsidies in context by country. We consider the types of subsidies, compare the size of consumer and producer subsidies for oil and gas, and briefly introduce the effects of producer subsidies.

2.1 Producer Subsidy Measures

For each member country, the OECD has categorized producer subsidies into a number of groups and subgroups. Transfer mechanisms include direct transfers, foregone taxes or government revenues, and risk transference as well as the point of direct incidence in the supply chain such as cost of various inputs or effects on revenue. These transfer mechanisms are summarized in Table 1.

Table 1 Subsidies for Producers in OECD Countries by Transfer Mechanism and Point of Direct Incidence

	Point of Direct Incidence					
Mechanism	**Income**	**Cost**				
		Intermed-iate inputs	**Capital**	**Land**	**Labor**	**Technology**
Transfer of funds	operating grant	input price subsidy	capital grant	capital grant for land acquisition	wage subsidy	R&D subsidy
Tax credit /exemption	production/ income/ resource-rent tax/ tariff credit/ reduction	reduction of excise tax on input	investment tax credit	property-tax/ royalty reduction or exemption	reduction in social charges (payroll taxes)	tax credit for private R&D
Transfer of risk	government buffer stock/third-party liability limit	security	credit guarantee for capital	credit guarantee for land	health and accident liabilities	
Induced transfers	import tariff/export subsidy	monopoly concession	credit control	land use control	wage control	intellectual property right rules

Source: OECD, 2013 [1].

The table also shows the point of impact for the transfer. The transfer can improve revenue from the production of oil or gas. Alternatively it can reduce costs for intermediate inputs, capital, land, and labor or reduce costs through improved technology. Generally, transfer of funds and tax credits/exemptions can be quantified directly, while other mechanisms indirectly influence producer behavior. The indirect transfers are harder to quantify and their evaluation is likely to be more subjective. For this reason, the OECD report cautions against adding the various subsidies together. Noting this caution, we nevertheless do add them to get a feel for the general magnitude of these subsidies as shown in table 2.

Detailed subsidies for income include exemptions from excise or severance taxes, financial assistance for exploration or development, tax deduction for exploration costs, exclusion of low-volume oil & gas wells, exemption from passive loss limitations and so on; capital formation includes accelerated depreciation, capital expenditure deductions for mining, exploration and prospecting, exploration subsidies, expensing of exploration and development costs, excess of percentage over cost depletion, enhanced oil recovery credit, qualified capital expenditure credit, and alternative credits for exploration; support for land includes excess of resource allowance over non deductibility of royalties, energy industry drilling stimulus, royalty tax credit or reductions; support for technology includes prospecting subsidies, oil product quality subsidies, and amortization of geological expenditure.

Table 2 Producer subsidies by type for 9 OECD member countries (Millions of USD, nominal)

		Point of Direct Incidence
Measures	**Income**	**Cost**

		Intermed-iate inputs	Capital	Land	Labor	Technology	Total
Transfer of funds	69.00	7.95	6.41			135.14	218.50
Tax credit /exemption	2651.48	274.48	3009.88	824.53		70.00	6830.37
Transfer of risk			553.66				553.66
Induced transfer		383.04					383.04
Total	2720.48	665.47	3569.95	824.53	0.00	205.14	7985.57

Source: OECD, 2012 [5].

2.2 The impacts of producer subsidies

Knowing what the subsidies are, the next step is to consider how the subsidies might influence producer behavior. Producer subsidies cover each phase of the upstream supply chain, and influence exploration, development and production activities. They include tax exemptions, direct grants, expense deductions and so on. For example, accelerated capital cost allowances allow firms to deduct expenditures on capital assets at a faster rate than for other businesses. Such accelerated depreciation reduces early tax burdens and the total life cycle discounted tax burden. This acceleration typically translates into a change in the objective function and, hence, a change in the optimal production profile. At the same time, this provision indirectly encourages investment, which in turn typically encourages innovative technologies and facilities. These technical changes will need to be translated into parameter changes for optimization models such as improving discovery rates or enhancing reserve levels by various means including sensitivity tests and examining historical data. Other translations to model parameters could include excess depletion translating into optimal production and decline rates and tax exemptions for exploration translating into improved finding rates.

These producer subsidies would change production profiles of oil and gas resources, and reduce their extraction costs. Since the above analyses are all qualitative, we next make a literature review of upstream decision models, which can quantitatively describe how the producer subsidies impact upstream decision making.

3. Review and categorizing upstream oil and gas models

In a companion draft report [6], we introduce some generic models to analyze producer subsidies and also summarize the models we are considering to analyze producer subsidies. So far we have found several oil and gas supply models, which contain upstream oil and gas modeling, and include elements from many of the generic models considered. Our first step has been to stratify them into a number of categories including model purpose, model methods, geographic scope, price formation, market structure, time horizon, inclusion of tax/subsidy, inclusion of technology, and demand formation.

Model purpose may include reserve discovery, discovery rate, drilling effort, finding rate, number of wells drilled, extraction cost, etc. Method includes econometric, process, optimization, and bottom-up modeling. Geographic scope includes a single well, field, company, region, nation, OPEC and even the whole world. Price formation includes scenario analysis with prices set exogenously or supply/demand equilibriums, which set prices endogenously. There are no price estimates in process and bottom-up models. Most models do not mention market structure but many implicitly are competitive markets with price equal to marginal cost. Time horizon is static or inter-temporal, where time spans may be decades in econometric models, and are often about 25 years in field lifecycle process, bottom-up and optimization models.

The element tax/subsidy indicates whether the model has included or can be easily adapted to include taxes or subsidies. A few econometric models include taxes and subsidies; optimization as well as bottom-up models generally contain them, but process models do not.

Technology is an important factor in the upstream oil and gas industry, so a model is more accurate with the inclusion of technical change. Technology is often represented by learning curves or may be included by increasing the success rate of drilling. Demand formation may be exogenous or demand may be modelled as a demand function making it endogenous.

Our classification of upstream oil and gas models along these lines is shown in Table 3, while we compare and analyze the models in each method group separately in the next section.

3.1 Optimization models

In upstream oil and natural gas exploration and development models, producers want the optimal utilization of scarce resources and capital. The optimization models are generally adopted to achieve optimal extraction paths. Livernois and Uhler [7] present both aggregate and disaggregate exploration-extraction models with the objective of maximizing the present value of profits for competitive firms with respect to reserves aggregated over many deposits and exogenous prices. Helmi-Oskoui [8] develops a model to maximize the present value of profits of the firm from the joint production of oil and gas from a given reservoir. The control variable is the bottom well-hole flowing pressure subject to the equation of motion, production capacity, and admissible control trajectory, and obtains an optimal time path under various tax policies. Rao [9] follows and develops the optimal pressure control technique with the objective of minimizing costs under constraints of exogenous demand, unit cost and other parameters such as the reserves to production ratio. Rehrl and Friedrich [10] establish a long-term oil price and extraction model to forecast future world oil supply and corresponding price paths. They use Hubbert curves to determine oil production in non-OPEC countries. OPEC is free to decide simultaneously its inter-temporal optimum with regard to its production and the associated price path. Leighty and Lin [11] develop an optimal dynamic oil production model. They construct field-level cost functions for constant return wells and decreasing return wells, and simulate the impacts of tax policy on the production rate. Smith [12] builds an integrated exploration and development model. He distinguishes primary production and enhanced production, and addresses many key tradeoffs affecting investors' decisions, such as the timing and scale of initial development, the rate at which production declines during the primary phase of recovery, and the time and intensity of enhanced recovery operations. Smith also tests the impacts of fiscal regimes.

We compare the basic important attributes of optimization models in Table 3, including optimization objective, decision variables, estimation methods, constraint and behavioral equations, exogenous variables in all equations, which might include reserves, costs, discount rate, and tax/subsidy. The objective is typically maximizing discounted present value of profits or minimizing discounted present value of costs. Our decision variables allow us to obtain the optimal results given our constraints. Such variables include production rate or bottom well-hole flowing pressure, which determines production. Reserves are generally estimated by geological analysis with historical data. Production is assessed using process models, forming standard production profiles, determined by engineering data including number of wells drilled, drilling rates, injection rates, etc. Costs are predicted by cost of inputs, such as wells drilled and technology, or by econometric methods. Constraints include remaining reserves, reserve-production ratios, reservoir pressure and technology, as well as domestic demand. The discount rate represents the capital returns and risk, which is important for intertemporal assessment. Discount rates representing different capital returns in sensitivity testing vary from 5% to 30%. Price is an important determinant of the value of the oil and gas properties as is cost. If price is endogenously set by supply and demand equilibrium, endogenous demand will be needed in the model. Alternatively, quantity demanded may be included as an exogenous constraint. If taxes and subsidies are included in the model, their changes and corresponding effects can be directly obtained.

Optimization models are established based on a theory of producer optimization behavior with economic targets and the constraints from the physical characteristics of resources. Subsidies or taxes affect economic benefits, and thus are included in the optimization models in general.

3.2 Process models

Process models are used to mathematically describe engineering processes such as production, discovery rate and reserves, etc. These supply models may be stand alone or may be pieces of larger models. Arps [13] uses the mathematical formulas describing the production decline rules. Arps' decline curve is widely applied and other decline curves are special cases of Arps' with different decline exponents (*n)* [14]. Arps and Roberts [15] present an exponential model of the number of discoveries for a particular size class with consideration of cumulative number of wildcat wells, basin size, areal extent, and an average exploration efficiency. Moore [16][17] use the Gompertz curve to fit cumulative production and discovery data. Hubbert [18] uses a bell-shaped curve to predict future production by fitting a logistic function to cumulative discoveries. The curve is only time-dependent and symmetric with one peak. Maggio and Cacciola [19] present variants of the Hubbert curve for forecasting world oil production. Kaufmann [20] combines the Hubbert curve and econometric models to simulate the finite supply of oil including oil price, gas price and production capacity. Laherrere [21] and Nashawi [22] develop multi-cycle Hubbert models, fitting the sum of a number of independent logistic production cycles to production data. Mohr and Evans [23] [24] build multi-function Hubbert models with one or more simple polynomials, after which the bell curve resumes, shifted to account for the additional cumulative production that occurred during the period of disrupted production. Michel [25] combines the probabilistic distribution into Hubbert models, with Pareto and gamma distributions to describe field sizes and the date at which each field starts to produce. Other models [26] [27] are derived from Hubbert functions. The Gaussian model is a Hubbert-like curve-fitting model. Brandt [28] uses an asymmetric version of the Gaussian curve to forecast production.

Table 4 displays the basic features of process models consisting of model purpose, structure, geographic scope, and determinant variables. For process models, mathematical functions are generally used to describe the process of discovery, drilling and formation of reserves, production, such as probability distributions, logistic growth and trend extrapolation and so on. The geographic scope of these models are generally fields, as well as regions or even aggregated to the national level. Model variables include exploratory feet drilled, ultimately recoverable reserves, time, and so on. These fundamental process models lack economic factors, such as demand or resource substitution. However, production is not only determined by geology, but also may be influenced by price. For example, Kaufmann [20] developed a production estimate model using econometric methods to adjust the result from a process model. These process models can be included in optimization or huge bottom-up models to describe the effects of geological and engineering factors on production, reserves, etc.

3.3 Econometric models

Equations for all of these models can be derived in various ways. Modelers may go back to engineering estimates, trade literature, and historical data. A popular technique, especially for economic behavioral equations is econometrics. Erickson et al. [29], Spann [30], Chollet [31], and Berman and Tuck [32] adopt log functions to estimate oil and gas discoveries of reserves. Cox and Wright [33] and Iledare [34] use log functions to describe the reserves found, drilling effort and finding rates. Walls [35] [36] [37], Khazzoom [38], Deegan [39], Attanasi [40], and Cleveland and Kaufmann [41] use linear or exponential functions to predict drilling footage, drilling costs, production, and the number of wells drilled.

Table 5 compares the characteristics of various econometric models found. These characteristics include model objective, determinant variables, functional form of the equations, whether data is lagged one or more periods (lag structure), the type of data used, and whether dummy variables are included to reflect discrete differences such as districts, policy changes, and time.

Dependent variables include reserves, production, number of wells drilled, drilling effort, finding rate, discovery size, drilling footage, cost etc. with pooled time series and cross-sectional data. Model variables include variables such as wellhead price, shutdown days, interest rate, demand, technical change, well cost, well depth, exploration kilometers drilled, and exploration maturity and parameters such as the substitution elasticity. Log and linear functional forms are the main model structures with reserves and price the most often lagged variables in the models. These econometric models do not closely conform to the physical character of exploration, discovery and operation (e.g., they do not contain reservoir pressure, oil saturation, water cut, or other physical aspects of oil production that drive production costs and rates). But these models can display the influences of physical and economic variables on production, reserves, etc.

3.4 Bottom-up models

Another popular type of model categorization is the perspective of the model. Top down models take a more aggregate point of view, while bottom-up models often consider more detail and may be quite large if many attributes of the energy sector are included [42]. Bottom-up models represent the supply chain of the upstream oil industry and forecast aggregate production as the sum of production from smaller units [43]. They also may be modules within other larger models.

MIT-POOL [44] presents models of supply of extractive resources including a reservoir development sub-model and an exploratory process sub-model applied in the North Sea. MARKAL [45] (Market Allocation Model) is a cost minimizing multi-year linear programming (LP) model developed by the Energy Technology Systems Analysis (ETSAP) Program of the IEA. The original model includes exogenous end-use energy service demand with detailed energy producing and consuming technologies. Technologies are represented by constant cost curves for each process. For example, the oil supply chain could be represented by costs for each step such as a cost of discovery and a cost of field development. The model allows for multiple regions and trade.

MARKAL has seen various reincarnations and versions including the addition of a macro growth model and allowing energy service demands to be made functions of price and income. The currently recommended version is the TIMES (The Integrated MARKAL-EFOM System) model [46] for a specific sector within a region up to an entire system with multiple regions. It not only allows demand to be a function of the price and income but also allows for a richer and more flexible representation of technologies with investment and vintaging of new technologies. When demand is a function of price, the model maximizes consumer plus producer surplus for the whole system.

OLOGSS-EIA [47] is the Onshore Lower 48 Oil and Gas Supply Submodule of the National Energy Modeling System (NEMS) created by U.S. EIA. OLOGSS utilizes exogenous data in known and undiscovered crude oil and natural gas fields or resources, and evaluates their economic benefits, ranking them by criterion including development, drilling and capital constraints, and finally forecasts the future supply. Kemp and Stephen [48] design financial simulation models for the projection of production and expenditures, using the Monte Carlo technique they estimate the number of new discoveries simulating over exploration effort, success rates, sizes, and whether discoveries are oil, gas, or condensate) of discovery and development costs simulating over operating conditions such as water depth and discovery size..

WEM (World Energy Model) [49] by the IEA is a large mathematical model that replicates how energy markets function consisting of final energy consumption, power generation and heat, refinery/petrochemicals and other transformation, fossil-fuel supply, CO_2 emissions and investment. LEAP (Long-Range Energy Alternatives Planning Model) [50] [51] follows an accounting framework to generate both energy demand and supply. The supply-side uses accounting and simulation approaches under alternative possible development scenarios.

Table 6 categorizes our bottom-up models starting with the reserve process through production. Within these models, different methods are used to determine costs; different discount rates are assumed and often varied for sensitivity testing; demand, taxes, and subsidies are included in different ways; final project ranking generally includes some form of NPV. Within these categories, geological databases and simulation may be used to characterize reserves; econometrics and decline curves may be used to characterize production profiles; econometrics equations as well as input cost may be used to characterize cost, which can include taxes and subsidies. Price is often exogenous but may come from other modules within a larger model. Although such modules are rich in detail, they are quite demanding in terms of variable inputs. Variable inaccuracy is likely to be reflected in their prediction.

Table 3 Categorizing Upstream Oil and Gas Models

	Model Name	Model Purpose	Method	Geographic Scope	Price Formation	Market Structure	Time Horizon	Tax/ Subsidy Included	Technology Included	Demand Formation
1	Erickson et al. (1974) [29]	Proved oil reserves	Econometric	U.S. Lower 48 states	Exogenous	No	1950-1968	Included in cost	No	No
2	Spann (1979) [30]	Oil and gas discoveries and production	Econometric	Field, national	Endogenous	No	No	No	No	No
3	Cox and Wright (1976) [33]	Reserves	Econometric	U.S. crude Petroleum producing industry	Endogenous	No	1959-1971	Included in price forecasting	No	Exogenous
4	Khazzoom(1971) [38]	Recoverable gas	Econometric	Reservoir, national	Endogenous	No	1961-1968	No	No	No
5	Walls (1994) [35]	Number of wells; production; reserves	Econometric & process	Reservoir	Endogenous, a random walk process	No	1971-1988	Included in operating profits	No	No
6	Uhler (1976) [53]	Discovered reserves	Process	Alberta	No	No	One year	No	No	No
7	Iledare (1995) [34]	drilling efforts, gross reserve additions	Econometric	West Virginia, 18,000 new wells drilled	Exogenous	No	1977-1987	No	Included in finding rate	no
8	API (1992) [52]	Production; marginal cost; present value of new reserve; cumulative/ addition reserves	Process	National	Exogenous	No	1966-2010	Included in cost	Included in cost and drilling footage	Drilling demand, endogenous
9	MacAvoy and Pindyck (1973) [54]	Non-associated and associated gas reserves	Econometric	Field, regional, national	Exogenous	No	1967-1971	No	No	Exogenous

Table 3 (cont.) Categorizing Upstream Oil and Gas Models

	Model Name	Model Purpose	Method	Geographic Scope	Price Formation	Market Structure	Time Horizon	Tax/ Subsidy Included	Technology Included	Demand Formation
10	Deegan (1979) [39]	Oil & gas discoveries	Econometric	Reservoir, oil and gas exploration industry	Exogenous	Competition	1946-1969	No	Included in Cobb-Douglas production function parameter	No
11	Chollet (1998) [31]	Rate of discovery and production	Econometric	U.S. Gulf of Mexico	Exogenous	No	1956-1985	No	No	No
12	Berman and Tuck (1994) [32]	Reserves, cost, number of wells	Econometric	U.S. and 11 oil producing country	No	No	1970-1989	Included in models	No	No
13	Attanasi (1979) [40]	Well number and expenditure	Econometric	Denver Basin	No	No	1957-1974	No	No	No
14	Cleveland and Kaufmann (1991) [41]	Yield per effort (YPE)	Econometric	National	Exogenous	No	1859-1988	No	No	No
15	Arps and Roberts (1958) [15]	Number of discoveries	Process	Cretaceous oil on the east flank of the Denver-Julesburg Basin	No	No	1944-1956	No	No	No
16	Livernois and Uhler (1987) [7]	Number of discoveries, extraction rate	Optimization	166 oil pool in Albert	Exogenous	competition	1950-1982	No	No	No
17	Rehrl and Friedrich (2006) [10]	Supply cost	Optimization	World	Endogenous	Monopoly: Dominant firm	To 2100	No	Exogenous technical progress cost reduction factor	Endogenous with price
18	Hubbert (1956) logistic [18]	Production	Process	Reservoir, regional, national	No	No	Field life cycle, decades	No	No	No

Table 3 (cont.) Categorizing Upstream Oil and Gas Models

	Model Name	Model Purpose	Method	Geographic Scope	Price Formation	Market Structure	Time Horizon	Tax/ Subsidy Included	Technology Included	Demand Formation
19	Probabilistic Hubbert (2010) [25]	Production	Process	Reservoir, regional, national	No	No	Field life cycle, decades	No	No	No
20	Multi-cycle Hubbert (1999) [21] [22]	Production	Process	Reservoir, regional, national, global	No	No	Field life cycle, decades	No	No	No
21	Multi-function Hubbert (2007) [23]	Production	Process	Reservoir, regional, national, global	No	No	Field life cycle, decades	No	No	No
22	Gaussian (2007) [28]	Production	Process	Reservoir, regional, national, global	No	No	Field life cycle, decades	No	No	No
23	Gompertz (1962) [16] [17]	Cumulative production or discovery	Process	Reservoir, regional, national, global	No	No	Field life cycle, decades	No	No	No
24	Kaufmann (1991) [20]	Production	Process, econometric	National	Exogenous	No	1947-1985	No	No	No
25	IEA-WEM (2010) [49]	Demand, supply	Bottom-up	Global	Demand and supply equilibrium, weighted average price	No	25 years	Included in average post-tax price	Included in technology cost	Sectoral and end-use demand
26	OLOGSS-EIA (2005) [47]	Oil and gas supply	Bottom-up	U.S. onshore	Supply and demand equilibrium	No	25 years	Included in cost	Adjust cost	Exogenous
27	Kemp and Stephen (2008) [48]	Production	Bottom-up	U.K. Continental Shelf	3 constant scenarios	No	25 years	Included in cost	Success rate of discovery	No

Table 3 (cont.) Categorizing Upstream Oil and Gas Models

	Model Name	Model Purpose	Method	Geographic Scope	Price Formation	Market Structure	Time Horizon	Tax/ Subsidy Included	Technology Included	Demand Formation
28	MIT-POOL (1976) [44]	Production	Bottom-up	North Sea	3 constant scenarios	No	23 years	Included in model	No	No
29	Leighty and Lin (2011) [11]	Production, reserves, cost	Optimization	Alaska	3 constant scenarios	No	1975-2045	Included in model	Included in drilling cost	No
30	Rao (2000) [9]	Cost, reserves, production	Optimization	Upstream oil sector in India	No	No	1993-2009	No	Included in constraints	Exogenous
31	Cleveland (1991) [55]	Supply Cost	Econometric	Lower 48 United States	No	Monopoly: Dominant firm	1936-1988	No	Included in cumulative drilling and production	No
32	MARKAL (2000) [45]	Energy supply and demand	Optimization	Regional, national	Endogenous	Competition	40-50 years	Included in model	Types of technology and penetration rate in constraints, exogenous learning curve	Endogenous
33	IEA-TIMES (2005) [46]	Energy supply and demand	Optimization	Local, regional and national	Exogenous	Competition	Time-slices defined by user	Included in cost	Included in input and output function	End-use per sector, endogenous
34	LEAP (2012) [50]	Energy consumption, extraction and production	Bottom-up accounting	National, global	Exogenous	No	20-50 years	Included in model	No	Driver and elasticity
35	Helmi-Oskoui (1992) [8]	Production	Optimization	Walton Canyon Reservoir in Pineview field	Expected average price	No	20 years	Included in model	No	Endogenous

Table 4 Comparison of Optimization Models

Optimization Models	Optimization object	Decision variables	Constraints	Discount rate	Tax/Subsidy Included	Price formation	Demand formation
Livernois and Uhler (1987) [7]	Present value of profits from exploration and extraction	Extraction rate, rate of exploratory effort	Remaining reserves, discovery rate	No	No	Exogenous	Endogenous
Helmi-Oskoui (1992) [8]	Present value of profits	Bottom well-hole flowing pressure	Reservoir pressure, production capacity, admissible control trajectory	15%, 20%	Included in model	Expected average price	No
Rao (2000) [9]	Discounted present value of supply cost from domestic and imports	Production rate	Reserve availability, pressure of reservoir, Production to reserve ratio, demand	No	No	No	Exogenous
Rehrl and Friedrich (2006) [10]	Present value of OPEC profits	Production, price path	Remaining OPEC reserves, production	Three scenario: 5%, 7.5%, 10%	Included in supply costs	Endogenous	Endogenous with price
Leighty and Lin (2011) [11]	Discounted present value of the entire stream of future profits	Production	Reserves, and production	Different districts: 2%-30%	Included in model	3 constant scenarios	No
Smith (2012) [12]	NPV	Extraction rate	Physical and economic constraints	8%	Included in cost	Random process	No

Table 4 (cont.) Comparison of Optimization Models

Optimization Models	Reserves		Production profile			Cost	
	Method	Determinants of reserves variables	Method	Production profile type	Determinants of production variables	Methods	Determinants of cost variables
Livernois and Uhler (1987) [7]	Exogenous	Geologic characteristic	Process	Standard production profile	Number of wells drilled, water and gas injection rate	Econometric	Reserves, production
Helmi-Oskoui (1992) [8]	Geological estimation	Geologic conditions	Process	Standard production profile	Pressure on the external boundaries of a reservoir and flowing bottom hole pressure	Cost driver	Labor cost, capital cost and operation cost
Rao (2000) [9]	Stochastic function	Discovery rate	Engineering	Standard production profile	Pressure on the external boundaries of a reservoir and flowing bottom hole pressure	Cost category	Costs of exploration, development and operation
Rehrl and Friedrich (2006) [10]	Exogenous	Geological conditions	OPEC: optimiz.; non-OPEC: Hubbert cycle	Non-OPEC: multi-cycle of Hubbert	OPEC: non-OPEC production and demand; Non-OPEC: ultimate recoverable reserves, peak year, steepness of curve	Unit cost per production	Technical progress, cost category, production, reserves
Leighty and Lin (2011) [11]	Historical data	Geologic conditions	3 constant scenarios	Mean, max, min	Specific for each field	Cost driver	Decreasing returns in production rate and time trends in production cost
Smith (2012) [12]	Geological analysis	Reservoir characteristic and technology	Process	Exponential decline	Decline rate, production capacity	Unit operating cost, marginal exploration cost	Production, number of wells drilled

Table 5 Comparison of Process Models

Model name	Model purpose	Model structure	Geographic scope	Determinants of model variables
Arps (1945) [13]	Production	Exponential, hyperbolic, harmonic	field	Productive capacity, decline rate
Arps and Roberts (1958) [15]	Number of discoveries	Exponential structure	Basin	Ultimate number of deposits in size class I, cumulative number of wildcat wells; basin size, average exploration efficiency
Hubbert (1956) logistic [18]	Production	Logistic function	Field to nation	Ultimate recoverable reserves, initial reserves and time
Probabilistic Hubbert (2010) [25]	Production	Logistic and Pareto distributed probability	Basin	Field size, ultimate recoverable reserves, initial reserves and time
Multi-cycle Hubbert (1999) [21]	Production	Logistic function	Nation	Number of cycles, peak production, peak time
Multi-function Hubbert (2007) [28]	Production	Logistic function	Nation	URR, production from bell-shaped curve model, a series polynomials at disruption points
Gaussian (2007) [23]	Production	Logistic function	Nation	Peak production, peak time, standard deviation of the bell curve
Gompertz (1962) [16] [17]	Cumulative production or discovery	Trend extrapolation	Basin	Ultimate production or reserves
Kaufmann (1991) [20]	Production	Logistic and regression	Region	Ultimate production, average of real oil prices, price of oil relative to natural gas, fraction of crude oil production capacity, first difference of the production curve after its peak

Table 6 Comparison of Econometric Models

Model name	Model purpose: Objective	Model purpose: Determinant variables	Model structure	Lagged variables	Dummy variables	Data types
Erickson et al. (1974) [29]	Proved oil reserves	Deflated average wellhead price, user cost of oil reserves, Texas shutdown days, district differences	Log and lag structure	Proved oil reserves, Texas shutdown days	District dummy variables	Pooled time-series and cross-sectional data
Spann (1979) [30]	Oil and gas discoveries and production	Discoveries: deflated wellhead price, Texas shutdown days, real interest rate; production: deflated wellhead price, Texas shutdown days, real interest rate, reserves	Log and lag structure	Discoveries: deflated wellhead price	No	Pooled time series and cross-sectional data
Cox and Wright (1976) [33]	Reserves	After-tax price, production, market-demand factor, substitution elasticity, technical change rate	Log structure	No	No	JAS,USBM, API data: pooling time series and cross-sectional data
Khazzoom (1971) [38]	Recoverable natural gas	Real ceiling price of gas, real oil wellhead price, liquefied petroleum gas price	Lag structure, linear or nonlinear	Recoverable natural gas	No	AGA data: time series
Walls (1994) [35]	Number of wells drilled	Present value of profits per well, weighted average number of OCS tracts leased, success ratio, dry hole cost	Linear structure	No	Time variable: 0, prior to 1983; 1, from 1983 to present	EIA, Shell, USGS data: time series and cross-section
Iledare (1995) [34]	Drilling effort, finding rate, discovery	Expected future effective tax rate, net before-tax cash flow, cumulative drilling effort, different operators, technical progress	Log structure	No	Different operators	Pooled time-series and cross-sectional data
MacAvoy and Pindyck (1973) [54]	Reserves, discovery size, wells drilled	Reserves: new discovery, extensions, revisions, changes in underground storages; discovery size: oil price, average well cost per foot, cumulative number of wells, regional field market; wells drilled: revenues, risk, well cost per foot, regional field market.	Lag structure	Reserves, total revenues, average drilling cost per foot, cumulative number of wells, discovery size.	Regional field market	Pooled time-series and cross-sectional data
Deegan (1979) [39]	Oil and gas discoveries	Present value of unit discovery, wholesale price index, income parameters, Cobb-Douglas production function, land input quantity	Exponential and lag structure	Price index	No	Pooled time-series and cross-sectional data

Notes: JAS represents Joint Association Survey; USBM denotes U.S Bureau of Mines.

Table 6 (cont.) Comparison of Econometric Models

Model name	Model purpose: Objective	Model purpose: Determinant variables	Model structure	Lagged variables	Dummy variables	Data types
Uhler (1976) [53]	Discovery	The time intervals of length, level of exploratory effort, cumulative exploratory footage	Log and lag structure	Cumulative exploratory footage	No	Time series
Chollet (1998) [31]	Reserves	Total exploration kilometers drilled, total cumulative exploratory depth, cumulative oil or gas discoveries, ultimate oil or gas reserves, oil wellhead price	Log and lag structure	Total exploration kilometers drilled, total cumulative exploratory depth, cumulative oil or gas discoveries, reserve additions	No	Pooled time-series and cross-sectional data
Berman and Tuck (1994) [32]	Gross reserve additions, drilling cost, number of wells drilled	Reserves: regional exploration maturity, present value price, number of wells; drilling cost: average well depth, number of wells, real price index of drilling cost-shift variables; number of wells: regional exploration maturity, present value price, average well depth, real price index of drilling cost-shift variables	Log and lag structure	Regional exploration maturity, cumulative production to cumulative reserves	No	Pooled time-series and cross-sectional data
Attanasi (1979)	Well drilled or drilling expenditures	Value of discoveries per time period in deposits of at least 500,000 barrels, expected exploration profit lagged two periods	Lag structure	Expected exploration profit	No	Pooled time-series and cross-sectional data
Cleveland and Kaufmann (1991) [40]	Modified yield per effort (YPE)	YPE_0, real wellhead price, rate of exploratory drilling, cumulative exploratory drilling	Exponential structure	No	No	Pooled time-series and cross-sectional data

Table 7 Comparison of Bottom-up Models

Bottom-up models	Reserves		Production profile			Cost		Discount rate	Tax/ Subsidy Included	Price formation	Project ranking
	Methods	**Determinants of reserves variables**	**Methods**	**Production profile type**	**Determinants of production variables**	**Methods**	**Determinants of cost variables**				
IEA-WEM (2010) [49]	Geological estimate	IEA, USGS database	Process	Standard production profile	Estimates of decline rate, size of reserves, physiographic situations	Unit cost capital and operating, adjusted by technology-driven cost reduction and country factor	Field types, technology progress, country factors	Vary between sector and region, 3%, 10%, representing cost of capital	Yes	Demand and supply equilibrium	NPV
OLOGSS-EIA (2005) [47]	Geological estimate	USGS database	Process	Lead-time(1yr) exponential decline	Exponential decline in wells	Cost driver	Number of wells, well depth, region	Post-tax weighted average cost of capital	Yes	Supply and demand equilibrium	NPV
Kemp and Stephen (2008) [48]	Monte Carlo simulation	Geological factors	Empirically estimated	Exponential decline	Specific for each field	Unit operating cost as a percent of development cost, varied to field size	Reserve size	Post tax discount rate: 10% , scenarios: 12.5%,15%	Yes	3 constant scenarios	NPV/I ratio
MIT-POOL (1976) [44]	Geological judgmental discovery	Rate of exploratory drilling	Empirically estimated	Field production profile	Reserve size category	Capital cost, fixed operating cost	Reserve size	Discount factor:18%, time preference and risk: 10%, general inflation: 8%	Yes	3 constant scenarios	NPV
LEAP (2012) [50]	Geological method	Geologic characteristic	Simulation	Standard production profile	Engineering data	Accounting	Engineering process	No	Yes	Exogenous	NPV
MARKAL (2000) [45]	Geologic estimation	Geologic data	Engineer-ing estimation	Standard production profile	Engineering data	Cost driver	Technology, import, production, material deliver	Global: 10%; new and advanced end-use technology: 25%	Yes	Endogenous	No
IEA-TIMES (2005) [46]	Statistic data	Geologic data	Engineer-ing estimation	Standard production profile	Engineering data	Cost driver	Technology, import, production, material deliver	Time-dependent	Yes	Exogenous	No

4. Model Recommendations

We have presented the aggregate subsidies in section 2, table 2 along with their transfer mechanism and point of impact. To choose the favored analytical tool from the many models surveyed, we need to know the transfer paths of the presented producer subsidies and subsequently what upstream decisions and variables, they are likely to impact.

We have not found any upstream models that can measure the impact of the induced transfers shown in Table 1, so we focus our attention on the other three transfer mechanisms or policies: transfer of funds, tax credits/exemptions, and transfer of risk. The policies have four points of impact: income, capital, land and technology. We pose four transfer paths, which are model components that transfer the subsidies to point of impact. They are price, cost, risk and cash flow as summarized in Table 8. The most important policies by far are tax credits and exemptions; these tax policies as well as transfers are transferred through price, cost and cash inflow. Whereas risk transfer operates through risk parameters to the capital stock.

Table 8 Category of producer subsidies and their transfer paths

Subsidies / Paths	Income	Capital	Land	Technology
Price	×			
Cost	×	×	×	×
Risk Parameter		×		
Cash Inflow	×	×		×

Now consider which points of impact can be influenced by which path as summarized in Table 8. Following specific subsidies are obtained from the OECD report for illustration [5], in which the detailed subsidies are categorized for 24 OECD countries. Income subsidies can be translated into the oil and gas models through three of the main paths. Since excise tax and severance tax act on oil and gas price, an exemption from excise or severance taxes influences other factors in the oil and gas supply chain or other sectors by price. Financial assistance for exploration and development as well as oil and gas allowances are direct transfers of funds for upstream exploitation. These subsidies can be directly translated into models as positive cash inflow. Tax deduction for exploration costs and exemptions from passive loss limitation add pre-tax deductible costs and thus reduce tax payments, so these subsidies can be translated into models as cost changes.

For a capital formation subsidy, there are three ways for them to be translated into models: cost, cash inflow, and risk parameter. Following detailed subsidies are also from OECD report [5]. Accelerated depreciation, capital expenditure deduction, exploration and prospecting deduction, expensing of exploration and development costs, and excess of percentage over cost depletion generate pre-tax deductible costs, which can be included in costs. An exploration subsidy is a transfer of funds and it translates into models as a positive cash inflow. An enhanced oil recovery credit, qualified capital expenditure credit and credit for exploration provide credit guarantees linked to capital. They reduce risk of capital acquirement, so these subsidies can be translated into models using risk factors or discount rates.

For land subsidies, most attention is focused on royalties. A depletion allowance, a royalty tax credit or other tax reduction decrease royalty payments and can be translated into models by royalties or costs.

Technology prospecting and oil product quality subsidies are transfers of funds, which can be translated into models through a positive cash inflow. Amortization of geological expenditure makes the geological expenditure recoverable in the production phase, and thus promotes more inputs into geological activities. This subsidy can be translated into models by costs.

The main transfer paths are presented for the detailed subsidies. In order to assess their impacts, we found the main upstream endogenous and exogenous variables for decision making, include reserves, production, number of wells drilled, and drilling footage. We list these main upstream decision variables that the subsidies may influence, and show the preferred model to analyze the effect of each subsidy path in Table 9. Our model choice depends on whether the subsidy can be included in the model and whether the affected variables are modeled as well. These models would, of course, have to be updated and estimated on a country by country basis before their application.

In general most producer subsidies can be translated directly or indirectly into any of the econometric or hybrid models that include econometric equations for upstream decision variables such as reserves, production, wells drilled, footage drilled, finding rates, discovery size, drilling footage and cost etc. Although these decision variables can be estimated by process models generally subsidies are difficult to include.

First consider the subsidies that can be modelled through the price transfer mechanism. As a main variable, price has impacts on the finding rate, reserves, production, number or footage of wells drilled, and drilling costs. Spann [30], Cox and Wright [33], Khazzoom [38], and Berman and Tuck [32] adopt price to forecast reserves, and the effects of price subsidies on reserves can be described by the above models. We recommend the Cox and Wright model [33], in which after-tax price is included in the reserves function, and other models use some kinds of prices or lagged prices which are more complex than the former. Cox and Wright derive an equation to estimate reserves with variables such as after-tax relative price, production and shutdown days etc. The impacts of income subsidies related to price on reserves are reflected through the after-tax relative price variable. The elasticity of reserves with respect to price is 0.033, so the removal of the subsidies related to price will slightly decrease reserves. Extensions to improve this model could include modeling price expectations and trends in geologic variables.

Rehrl and Friedrich [10], Deegan [39], and Smith [12] model production with price, which can be used to analyze the influence of price subsidies on production. At a global level, the Rehrl and

Friedrich model [10] is recommended as a starting point to analyze the price influence, because Smith model is applicable for field level, and Deegan uses price index. Rehrl and Friedrich generate long-term scenarios regarding future world oil supply and the corresponding price paths and develop optimal OPEC extraction paths under the constraints of a price-dependent world oil demand. First, a given price path is used in the OPEC module to calculate the price-output balance that is inter-temporally optimal for OPEC, and then the optimized price path is transferred to the non-OPEC module and consecutive iterative price path solutions can be observed. The subsidy related to price can be included in the OPEC production optimization module, and its impacts will spread throughout OPEC and the non-OPEC production prediction. This model simulates the production and price paths between non-OPEC and OPEC, and the influence of subsidies related to price on world oil supply can be observed. Although this model considers the interactions between OPEC and non-OPEC players, it could benefit from a number of improvements. Non-OPEC production is estimated by Hubbert cycles without considering economic factors and inter-temporal allocation for them, and world oil demand is described by means of a reference scenario without considering other factors such as structural changes in demand.

Table 9 Model recommendation for upstream decision variables under various transfer paths

Transfer Paths	Reserves Found	Production	Number of Wells Drilled	Drilling Footage
Price	Cox and Wright [33]	Rehrl and Friedrich [10], Smith [12]	Berman and Tuck [32]	Iledare [34]
Cost	Erickson et al. [29]	Rao [9], Livernois and Uhler [7], Helmi-Oskoui [8], Leighty and Lin [11]	Walls [35]	Iledare [34]
Risk	MacAvoy and Pindyck [54]	Livernois and Uhler [7], Helmi-Oskoui [8], Rao [9], Rehrl and Friedrich [10], Leighty and Lin [11]	MacAvoy and Pindyck [54]	*
Cash Inflow	Iledare [34]	Leighty and Lin [11], Livernois and Uhler [7], Rehrl and Friedrich [10], Helmi-Oskoui [8]	Walls [35]	Iledare [34]

* Although no existing model has included a risk transfer mechanism, Iledare (1995)[34] could be modified to include it as mentioned in the text.

We recommend the Smith model [12] to analyze the impacts of subsidies transferred through price on production for a single field or nation. He emphasizes the role of enhanced oil recovery in an integrated optimization model of investment and finds an optimal production path using an optimal exploration and development model with maximum profits as the objective. The subsidy related to price can be included to reflect its impacts on optimal production. This model fully describes the entire process of oil exploration and development with integrating decisions regarding primary and enhanced oil recovery (EOR). It shows the influence of fiscal regimes on the scope and efficiency of resource exploitation. The impacts of subsidies on production can be easily calculated with this model. Smith adopts an assumed exponential decline to describe production. Beneficial extensions to this model would include allowing more flexible models of decline rates as well as considering the relationship among decline rate, EOR and recovery.

The Iledare model [34] is recommended to describe the influence of a subsidy related to price on drilling footage, because this is the only drilling footage model including price. Iledare develops a log-linear approximation model of drilling footage with net before-tax cash flow, effective tax rate, and dummy variables for different operators, and cumulative drilling effort. So the impacts of a subsidy on drilling footage can be observed through net before-tax cash flow and the effective tax rate. The elasticity of drilling footage with respect to net before-tax cash flow is 0.525; thus, price subsidy removal will decrease drilling footage. This model makes use of geological, engineering, economic and policy information at the micro level of the individual fields and depth categories, and is used in a mature geological setting. It can be easy to evaluate the response of activity within individual geological series to prices, taxes and costs.

Attanasi [40], Berman and Tuck [32] describe the number of wells drilled with price. The Berman and Tuck model [32] is recommended, because Attanasi's model is only used for wildcat-drilling behavior. Berman and Tuck develop an equation to estimate the number of wells drilled with variables such as regional exploration maturity, time period, expected effective real present value of net price, average well depth and a real price index of drilling cost-shift variables. A price related subsidy can be included in this model in the expected effective after-tax price. The elasticity of wells drilled with respect to oil price ranges from 0.2 to 0.5 for most countries, so removal of these subsidies will reduce wells drilled. This model quantifies exploration maturity by cumulative production-to-reserves, which combines technology and acknowledges that this factor is important for drilling.

Subsidies to capital, land and technology are likely to be transferred through cost, which should have impacts on finding rate, reserves, production, number of wells drilled, and drilling cost. Erickson [29], MacAvoy and Pindyck [54] develop the models of reserves with cost. Erickson et al. [29] is recommended to describe the influence of the subsidies on reserves, because the taxes are directly included in the costs. They develop a model to forecast reserves with the following independent variables: deflated average wellhead price, user cost of oil reserves (including opportunity cost as well as finding cost with expenditures expensed for tax purposes), with a current value and one lag for shutdown days, district dummy variables and one-period lagged reserves. The elasticity of reserves with respect to costs is -0.069, so the removal of subsidies related to costs will decrease reserves. Extensions to improve this model include considering the impacts of development costs and production-to-reserves ratio on reserves.

Leighty and Lin [11], Livernois and Uhler [7], Rehrl and Friedrich [10], Rao [9] and Helmi-Oskoui [8] present optimization models with production as the decision variable. Some include cost as an objective function, while others include it as an exogenous variable in their profit function. We would use the Livernois and Uhler [7], Helmi-Oskoui [8], Rao [9], and Leighty and

Lin [11] to analyze the influence of the subsidies related to costs on production, because Rehrl and Friedrich estimate the non-OPEC production with Hubbert curve and thus the impacts of cost on production cannot be transferred. Rao adopts a dynamic non-linear programming (NLP) model. His objective is to minimize the discounted present value of overall economic cost of total supply (ex-reservoir) of oil and gas from domestic reservoirs and imports in order to meet the demand for each year in the model, subject to the production-to-reserve ratio, domestic demand, investment and reservoir pressure, etc. Subsidies can be included in the objective function to achieve optimal production. The detailed pressure at external boundaries of the reservoir and flowing pressure at the bottom of the well are required for this model, so it is a huge and complex optimization system. Extensions to simplify this model include using decline rate to describe changes in production. Livernois and Uhler [7], Helmi-Oskoui [8] and Leighty and Lin [11] presents models of maximizing discounted benefits with control variable of production, and costs are used to calculate the benefits, so the impacts of subsidies related to costs can be obtained via the optimization.

Walls [35] and Attanasi [40] model the number of wells drilled with costs. We would adopt the Walls [35] model to describe the influence of the subsidies related to costs on the number of wells drilled, because the Attanasi model is used for wildcat-welling behavior. Walls estimates the number of wells drilled as a function of expected discounted present value of profits per well, the weighted average number of OCS tracts leased and dummy variables for time. The discounted present value of profits is calculated using operating profits, success ratios, and drilling costs from successful and dry holes. Cost subsidies can be included in the discounted present value of profits function through costs, and then their impacts on the number of wells drilled can be observed. This model combines engineering analysis and economic benefits as well as econometric estimation, considering costs of dry holes and success ratios of wells, so this is a “hybrid” model to estimate the number of wells drilled.

We would again recommend Iledare [34] to analyze the impact of cost on drilling footage, because this is the only model to estimate the drilling footage with cost. With the same model, the cost can be included to calculate net before-tax cash flow, so the subsidies for income, capital, land and technology related to costs exert their impacts on drilling footage through the cost path, the same as price. The elasticity of drilling footage with respect to net before-tax cash flow is 0.525. Thus, the removal of subsidies related to costs will increase drilling footage.

Risk is typically transferred in two ways either through a risk factor or a discount rate. The literature includes risk in modelling reserves, production, and wells drilled. We would recommend MacAvoy and Pindyck [54] to describe the influence of capital subsidies related to risk on reserves found and number of wells drilled, and also because this one is the only model to estimate the reserves found and number of wells drilled with risk. In their series of models, total exploratory wells drilled are regressed on total revenues, average total drilling costs and a risk factor as well as dummy variables for different regional markets. The elasticity of wells drilled with respect to risk is -2.087, so the removal of subsidies related to their risk factor will reduce drilling. This in turn will reduce reserves found. We also recommend MacAvoy and Pindyck [54] to describe this influence of risk on reserves. They sum new discoveries, extensions, revisions and subtract changes in underground storage, losses and production to generate reserves. This is the only model that considers risk in the estimation of reserves by econometric methods. Although the risk factor in their model reflects the risk among different regions, we still can quantify and translate the subsidies related to risk into their model.

The inter-temporal optimization models (Livernois and Uhler [7], Helmi-Oskoui [8], Rao [9], Rehrl and Friedrich [10], and Leighty and Lin [11]) with production as an endogenous variable can be adopted to describe the effects of risk on production. We would adopt each of them to analyze the impacts of capital risk subsidies on production. They develop optimization models to maximize the discounted present value of the entire stream of future profits from oil production. The risk subsidies can be included in their optimization model through the discount rate, and their impacts can be obtained. Not too much data on exploitation is needed for Leighty and Lin model, so this model is applicable to development of new field rather than existing fields. However, Helmi-Oskoui [8] and Rao [9] use reservoir pressure to estimate production, and the models can apply in the mature fields with detailed process data. Meanwhile, Rehrl and Friedrich [10] model OPEC production with risk and spread the impacts to non-OPEC by demand-price paths.

No existing models directly include risk in estimating drilling footage or drilling costs. However, one could try including risk in the form of the interest rate directly in the footage equation of Iledare [34].

From the perspective of cash inflow, parts of income, capital and technology subsidies can be translated into a cash inflow. The cash inflow may influence reserves, production, wells drilled, and footage.

The Iledare [34] model is recommended to describe the influence of subsidies related to cash inflow on reserves, because this is the only model describe the reserves with cash inflow. He develops a gross hydrocarbon reserve addition model consisting of the proportion of successful effort, the drilling effort and effectiveness of drilling at adding new reserves. Drilling effort is calculated as net before-tax cash flow and other variables, and then the cash inflow can be directly added into the net cash flow variable, the same as price. So the impacts of subsidies related to cash inflow on reserves can be observed. Cash flow is also included in his drilling equation. The elasticity of drilling footage with respect to net before-tax cash flow is 0.525, so the removal of subsidies related to cash inflow will decrease drilling footage.

The optimization models are usually adopted to present the effects of cash inflow on production, such as Leighty and Lin [11], Livernois and Uhler [7], Rehrl and Friedrich [10], and Helmi-Oskoui [8]. We recommend all of them to analyze the impacts of subsidies related to cash inflow on production. These subsidies can be added into the objective functions as cash inflow, and their impacts on optimal production can be obtained.

Walls [35] is recommended to describe the influence of subsidies related to cash inflow on the number of wells drilled, because this is the only model to analyze this impact. She regresses wells drilled on the expected present value of profits per well, dummy variables for time and a weighted average number of Outer Continental Shelf (OCS) tracts leased. The subsidies can be included in the present value of profits per well function, and thus the impacts of these subsidies related to cash inflow on the number of wells drilled can be observed.

5. Conclusions

In this paper, we have set the stage for evaluating upstream oil and gas subsidies for OECD countries. We qualitatively analyze the impacts of producer subsidies on upstream decision making using detailed data collected by the OECD. In order to quantitatively evaluate their influence, we conduct a literature review of upstream oil and gas models, and categorized them into several groups by modeling method. We have compared and discussed the main features of the models in each group, and outlined the general structure, variables, data required, and application scopes and requirements. We summarize the transfer paths by which the subsidies can be translated in the upstream models, including price, cost, risk parameter and cash inflow. Reserves, production, number of wells drilled, and drilling footage are picked as decision variables that these subsidies may influence. Finally the appropriate models are recommended for various decision variables.

We have recommended what we consider to be the best in class amongst existing model for upstream analysis, our next step will be to consider whether we can combine or modify the above models for a more general improved model, incorporate any new models that crop up, consider any country specific modifications that might need to be considered, and consider how removal of subsidies might affect the wider economy, for example, drilling will require labor and influence labor market; investment will require capital and may influence interest rate. We will also consider model adaptations that could make the existing models more effective for the task.

Any modelling should consider the recent shale oil and gas boom. For shale oil and gas, horizontal wells and fracturing are applied to the field. The length of the horizontal segment, the stage and half-length of fracturing, and the amount of proppant impact both the production profile and costs. The production decline can be represented as for conventional resources as in [56] [57] [58]: exponential decline, hyperbolic decline, and a switch from hyperbolic to exponential decline [59]. The costs include drilling costs from vertical and horizontal sections, fracturing and refracturing costs, and proppant costs, as well as operating costs [60]. The optimization models can be adopted to get the optimal production profile, with targets of maximizing the discounted present value of benefits, such as Livernois and Uhler [7], Helmi-Oskoui [8], Leighty and Lin [11], Smith [12] or minimizing costs, such as Rao [9]. The models should be modified with the faster production decline typical of shale oil and gas, fracturing and refracturing costs and benefits, etc. Econometric models can be adopted to estimate the reserves found, such as Cox an,d Wright [33], Erickson et al. [29], MacAvoy and Pindyck [54], Iledare [34]; drilling footage, such as Iledare [34], and the number of wells drilled, such as Berman and Tuck [32], Walls [35], MacAvoy and Pindyck [54]. The technological gains and market conditions (service sector, labor market), as well as environmental costs should be considered when modifying the models.

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