Implications of tariff and tax benefits for oil development in East Siberia

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This paper proposes an approach to optimisation of oil production tax incentives built around the cumulative discounted value including taxes. Given a simplified oilfield model, optimum tax and tariff rates (their totals) are identified.

Index terms: **oil production, tax rates, tariff, model, optimum.**

1. INTRODUCTION

At present, East Siberian oil development offers tax (MRET = mineral resources extraction tax), export duty, and transportation tariff (for ESPO oil pipeline and rail shipments to Kozmino terminal on the Pacific Coast) benefits. It is believed critical to address implications of tax incentives for regional oil production and, conversely, production effects for tax take.

2. METHODOLOGY APPROACH

Business investment decisions are commonly built around net present value (*NPV*) and its levels against necessary Capex.

Similar to *NPV*, we can introduce here a discounted cumulative tax take (*DCT*) over the entire field life. The *DCT* can be justified by potential tax shortage over time which the government can effectively offset through the issue of bonds and other financial facilities. The chosen discount factor, *E*, should be at or above the bonds interest rate.

Here, we evaluate the tax level as a rate, *h* (dollars/tonne), or *DCT* to cumulative discounted oil production (*CDOP*) ratio. If a target field appears immune to tax burden changes, then the lower *h* would typically lead to proportionally smaller *DCT*.

However, an oilfield is known to be a very flexible development target. If designers need to optimise the development project, then, depending on tax rates, different projects appear as a result, as well as their own *DCT* levels.

Given the development project optimisation efforts by investors, the effect of a particular tax incentive can be seen as growth in production and even in the absolute value of *DCT*.

For simplicity, the tax rate, *h*, will also include oil transportation tariff across the ESPO pipeline.

Now assume that an investor adopts the project when the following is valid:

$$\Delta NPV > f \cdot \Delta DCC \tag{1}$$

Where: *DCC* = Discounted Cumulative Capex, and *f* = investment marginal performance. Essentially, this implies maximisation of *f*-criterion – $NPV\text{-}f{\cdot}DCC$.

The proposed approach is believed mainly applicable to new fields.

3. FIELD DEVELOPMENT MODEL

For numerical estimates, a simplified field development model is employed here [1].

This field can be characterised by initial recoverable oil reserves, Q_0; relative Opex, *c* (excluding asset depreciation); relative Capex per unit capacity, *k*; and fixed Capex, $K_\text{ф}$. This development project has a flat recovery rate, *m*, for which reason its oil output is exponentially falling over time, *t*, with (*-mt*) index.

The following external conditions were assumed: world oil price, *p* = \$520/t; export duty = \$70/t; ESPO tariff = \$50/t; average MRET (with tax incentives) = \$55/t. This produces: *h* = 70 + 50 + 55 = \$175/t. Assume: *f* = 100%, and *E* = 10%.

The following will be assumed for this field: Q_0 = 200 million t, *k* = \$800/t/yr, $K_\text{ф}$ = \$80 million, and *c* = \$120/t.

Field development characteristics – *DCC, NPV, IRR, DCT*, and *f*-criterion – as a function of recovery rate, *m*, are shown in Fig. 1.

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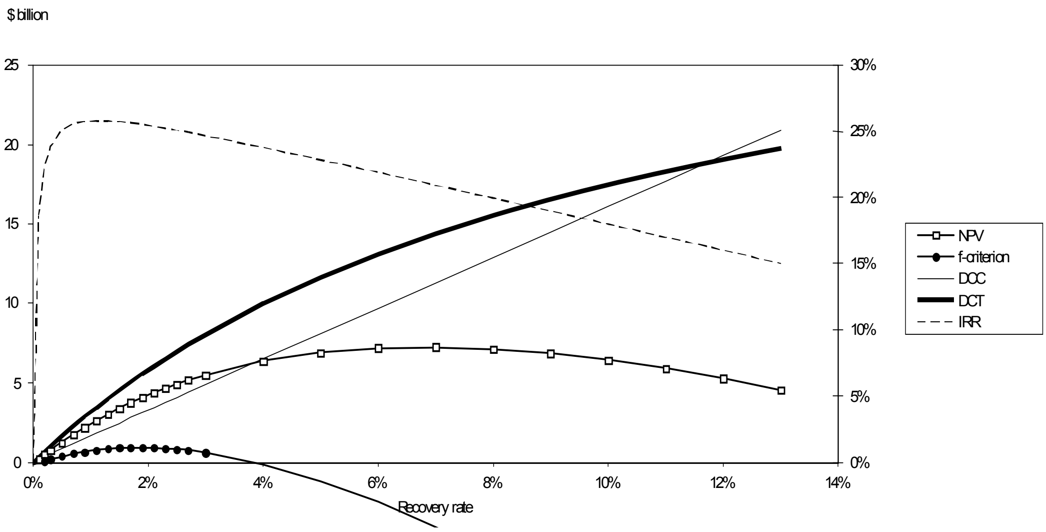

Fig. 1. Field development performance vs. offtakes

Under growing recovery rate, m, both the Capex and the taxes tend to rise, but *NPV* is peaking at m_0 = 7%. The optimum criterion, $NPV\text{-}f{\cdot}DCC$, has positive maximum at m_f = 1.86% thereby limiting tax receipts by *DCT* = $5.6 billion. An investor is unlikely to move his recovery above m_f to avoid violating conditions for investment performance (see. Eq. 1). *IRR* would be at 20.9% under the highest *NPV* and at 25.5% under maximum *f*-criterion. Here, we assume the fixed recovery rate, m_f, for the field.

$$m_f = \sqrt{\frac{(p-c-h)E}{(1+f)k}} - E \qquad (2)$$

4. IMPACTS OF TAX INCENTIVES

4.1. Tax breaks implications for recovery rate

Fig. 2 shows field performance profile as a tax function, h, under recovery rate, $m_f(h)$.

What happens if the tax rate, h, is reduced from $175 to $170/t? Assuming the recovery rate at m = 1.86% remains unchanged, *DCT* would be down $157 million.

Now make provisions that the optimum recovery rate, m_f, is 2%, which implies a 7% higher maximum field production level. In his case *DCT*, rather than falling, would actually grow by $157 million.

In total, this incentive has led *DCT* to grow, as a result of optimisation, by $313 million. A tax incentive consistency ratio, $k_{сл}$, could be introduced, comprising a ratio between higher tax due to optimisation and smaller tax as a result of changing tax rate, h. Produce:

$$k_{сл} = \frac{Eh}{2m_f(p-c-h)} \qquad (3)$$

In case that $k_{сл}>1$, such incentive would lead to a higher-tax business environment. In this case, $k_{сл} = 2$.

Under smaller h, all field development conditions tend to improve, but the taxes, *DCT*, under h = $140/t, would be peaking. In this point: m_f = 2.75%, *DCT* = $6 billion, *NPV* = $6.7 billion, and *IRR* = 29.2%. Production plateau at this field would rise by 48% against h = 175, *DCT* 10% up, *NPV* = 68% higher, and *IRR* rising by 14%.

Tax reduction by $35/t could be achievable either through MRET, or export duty, or ESPO tariff, or through all above mentioned taxes, to various extent.

Under $k_{сл} < 1$ (h < $130/t) *DCT* for oil tends to go down, but production is well supported, even leading to some added budget revenues due to a multiplicative effect.

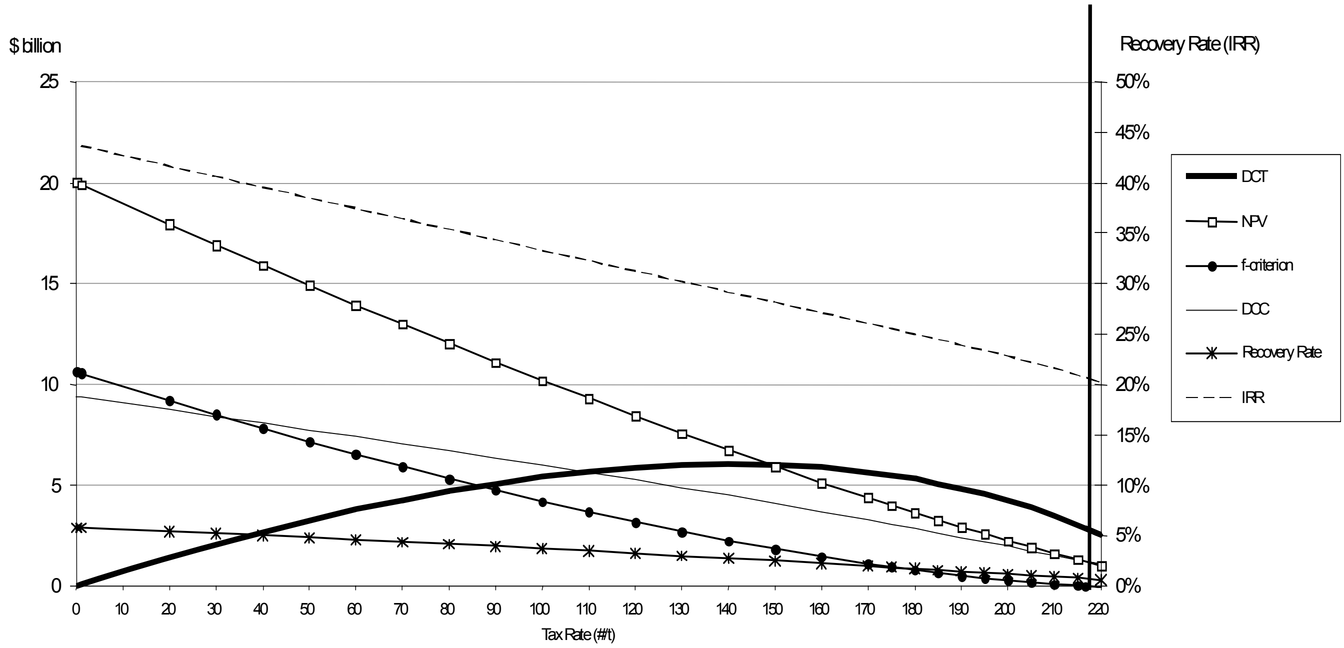

Fig. 2. Field performance vs. tax rate

4.2. Implications of tax breaks for bringing a field onstream

Introduction of such tax incentives would likely change the sign of the *f*-criterion and bring profitable field production. For example, under h = \$217/t or higher, Eq. 1 would not apply, for which reason all curves in Fig. 2 right of the vertical line would be inapplicable in practice. Let the rate, h, be falling from \$220 to \$215/t. Under h = \$220, there is neither the production, no tax inflows. Under h = \$215, the optimum recovery would be at m_f = 0.75% rate, while *DCT* rises to \$3 billion. This is also beneficial for investors, as *NPV* would be \$1.31 billion at *DCC* = \$1.28 billion and *IRR* at 20.9%. This outcome is likely when the following inequality (efficient field entry condition) applies:

$$p > c + h + (1 + f)\left[k + \frac{K_{ф}}{m_f(h) \cdot Q_0}\right] \quad (4)$$

4.3. Oil price effects

Equation $k_{сл}$=1 helps to identify the tax rate, h_f, to maximise *DCT*. Fig. 3 shows its average oil price relationship, in dollars per barrel, over the entire field life. For comparison, Fig, 3 also indicates the tax levels without incentives (i.e. the totals combining export duty for Urals Blend, MRET excluding breaks, and ESPO tariff) and taxes with incentives for ESPO pipeline (export duty = 45% under p > \$50/t, MRET with tax break, and ESPO tariff).

It should be noted that introduction of the MRET incentive for the addressed field corresponds to 70–30% lower cumulative discounted MRET, depending on recovery rate, m, from 0.7% to 6%; but a 40% reduction was chosen for Fig. 3. It can be seen that in terms of tax flow maximisation, the optimum curve at \$50/bbl oil or higher would be close to a polygonal line for ESPO, but it would be more steep (see Fig. 4 for line angles shown in Fig. 3).

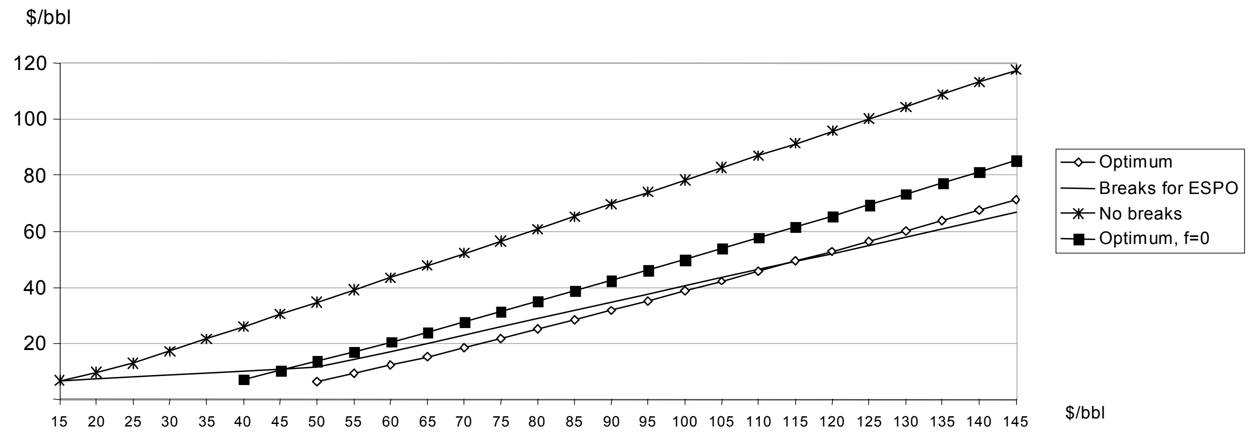

Fig. 3. Oil price relationship for tax rate

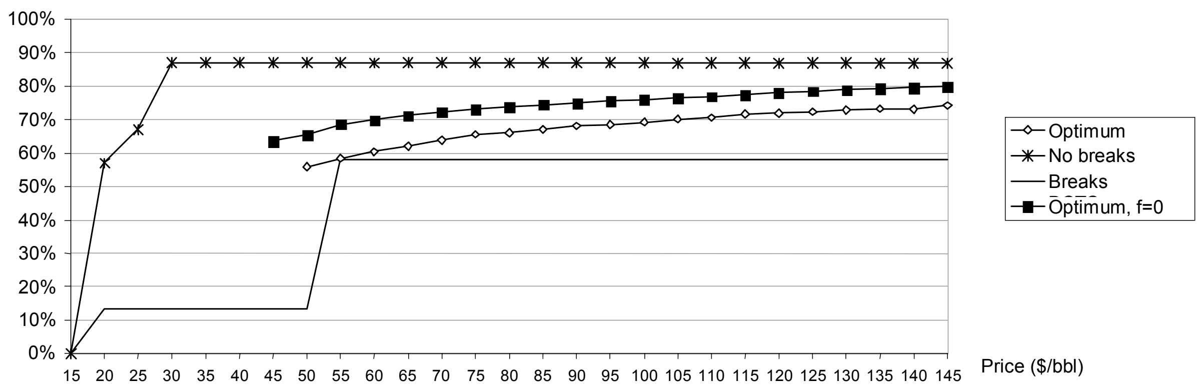

Fig. 4. Line slopes for tax formula

No MRET applies under oil at $50/bbl. With oil under $50, development of this field would be unprofitable.

4.4. Field development conditions impact

Here we address the case for $f = 0$, i.e. when investors look to bringing onstream all fields under $NPV > 0$ and choose the recovery rate, m_0, to deliver maximum NPV for the field. The outcome is summarised in Figs. 3 and 4.

Significant difference can be seen, and it is beneficial for the state. However, investors have the last word to say under choice of f. In Figs. 5 through 11, NPV, DCC, NPV/DCC, IRR, DCT, m, and h are shown as functions of oil price for a series of estimates differing from the base case in a single parameter:

- $f = 0$;
- k = $600/t/year;
- k = $1,000/t/year;
- $K_ф$ = $800 million;
- $K_ф$ = $0 million;
- c = $40/t;
- c = $150/t.

It can be seen that the $f = 0$ option differs from all others by lower NPV (under price above $500/t) and higher DCC, for which reason featuring the lower average capital efficiency, NPV/DCC, as shown in. Fig. 7.

This option offers higher extraction rates and taxes, DCT. The highest potential annual production for the oilfield in question can be assessed from both the recovery rate and field's recoverable reserves.

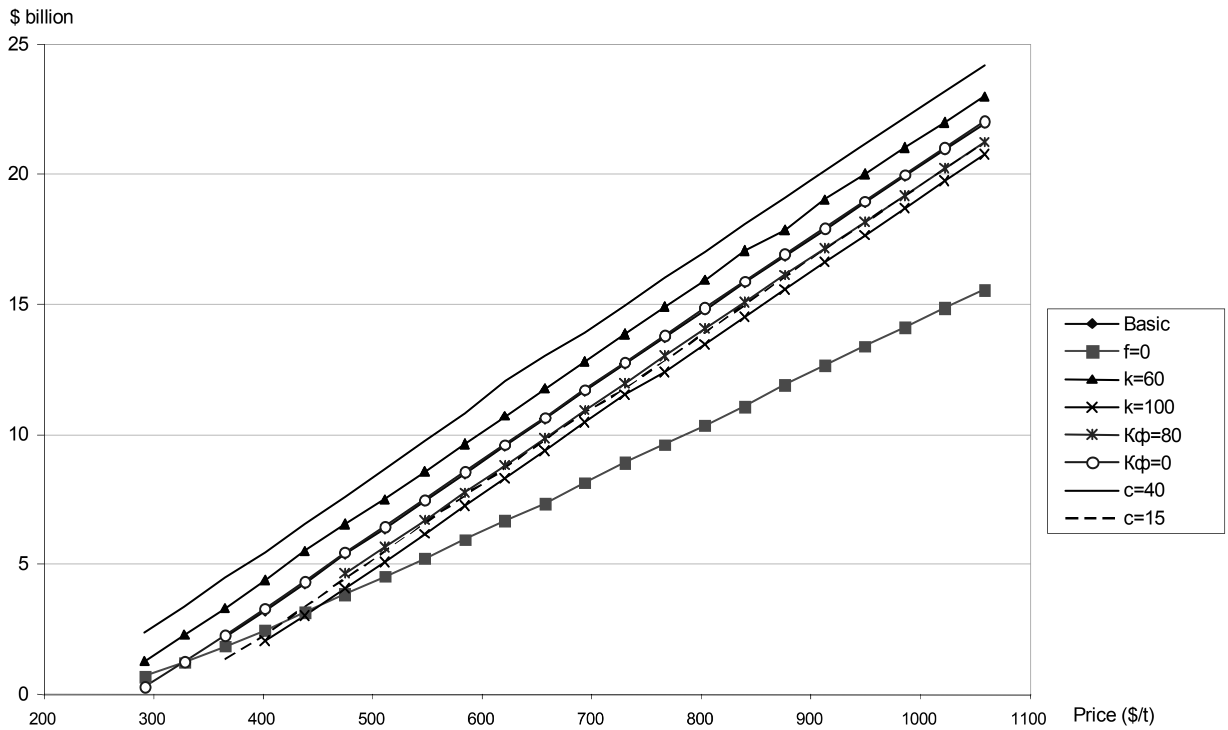

Fig. 5. Net Present Value (*NPV*)

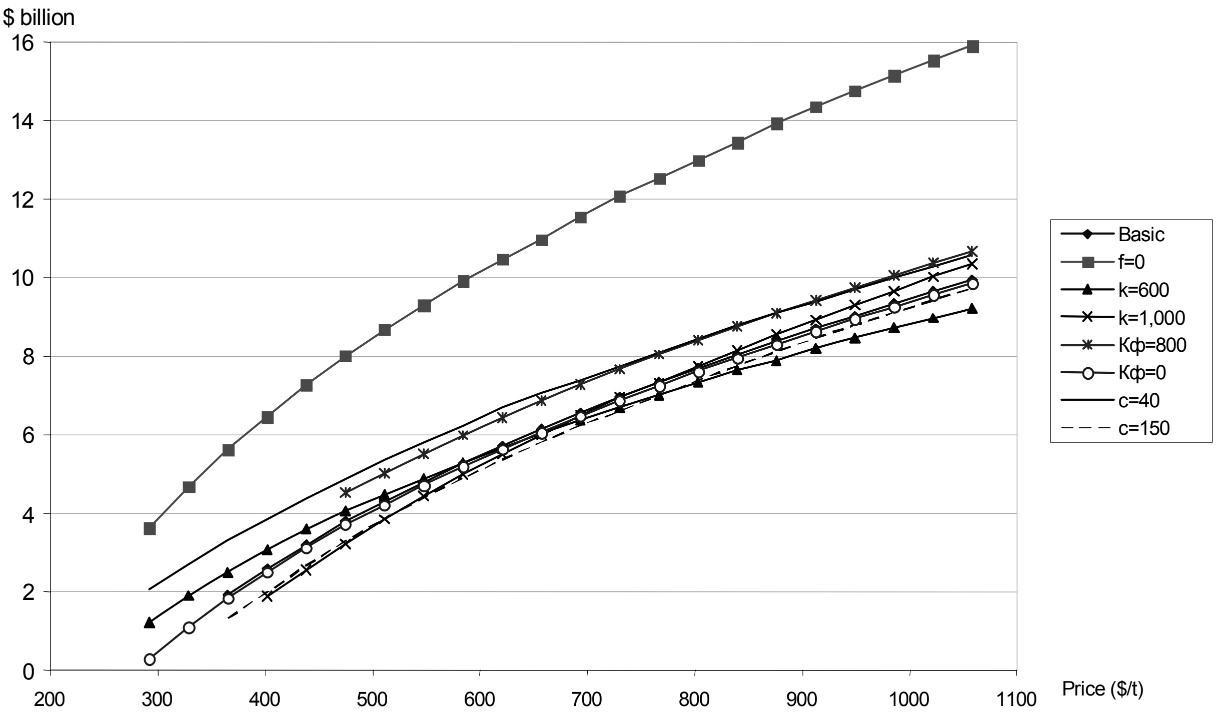

Fig. 6. Discounted Cumulative Capex (*DCC*)

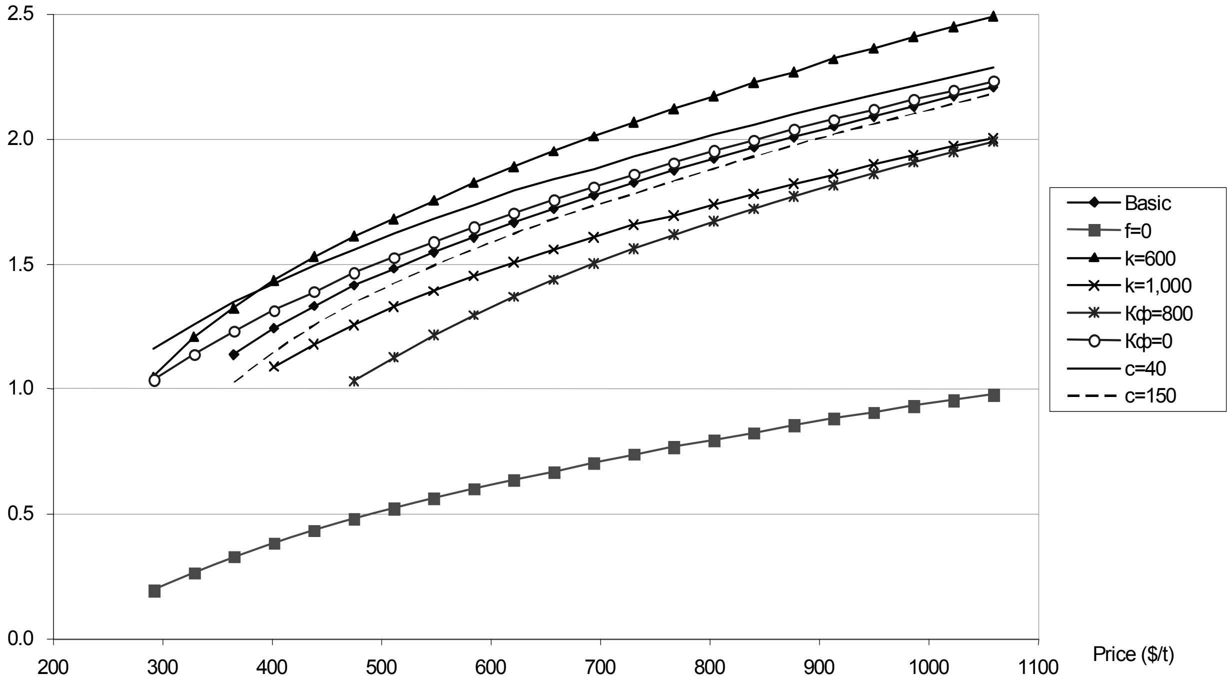

Fig. 7. *NPV/DCC* ratio

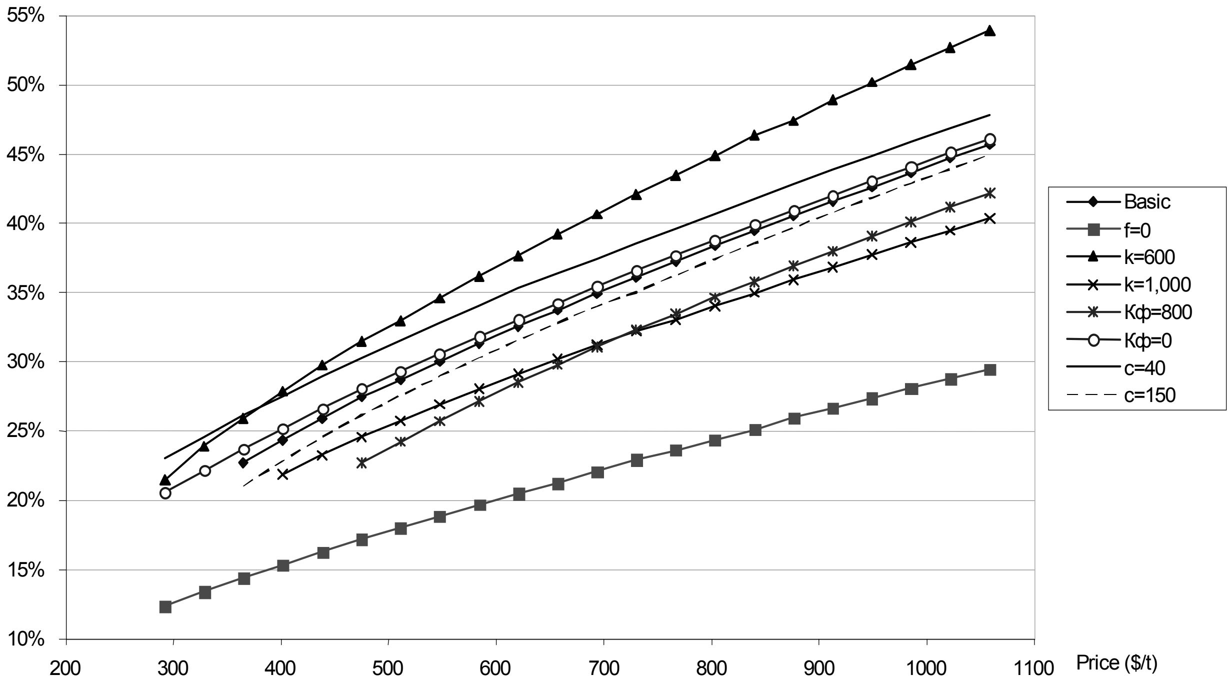

Fig. 8. Internal Rate of Return (*IRR*)

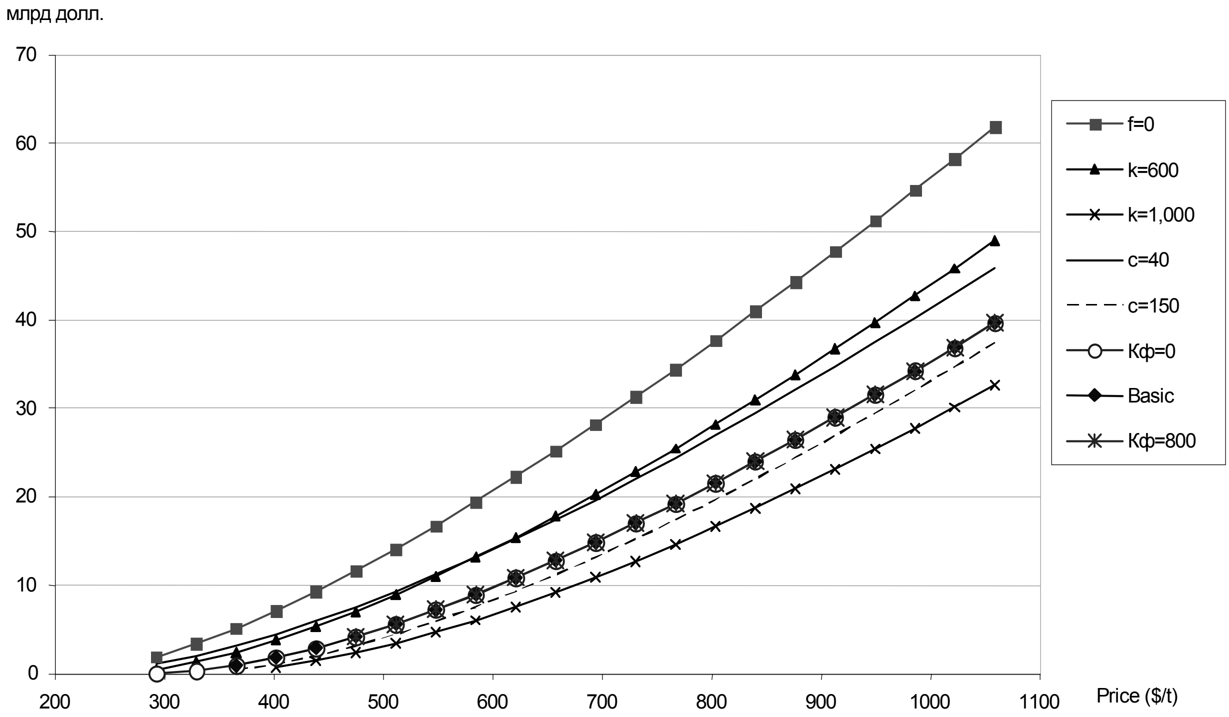

Fig. 9. Discounted cumulative taxes and transportation costs (*DCT*)

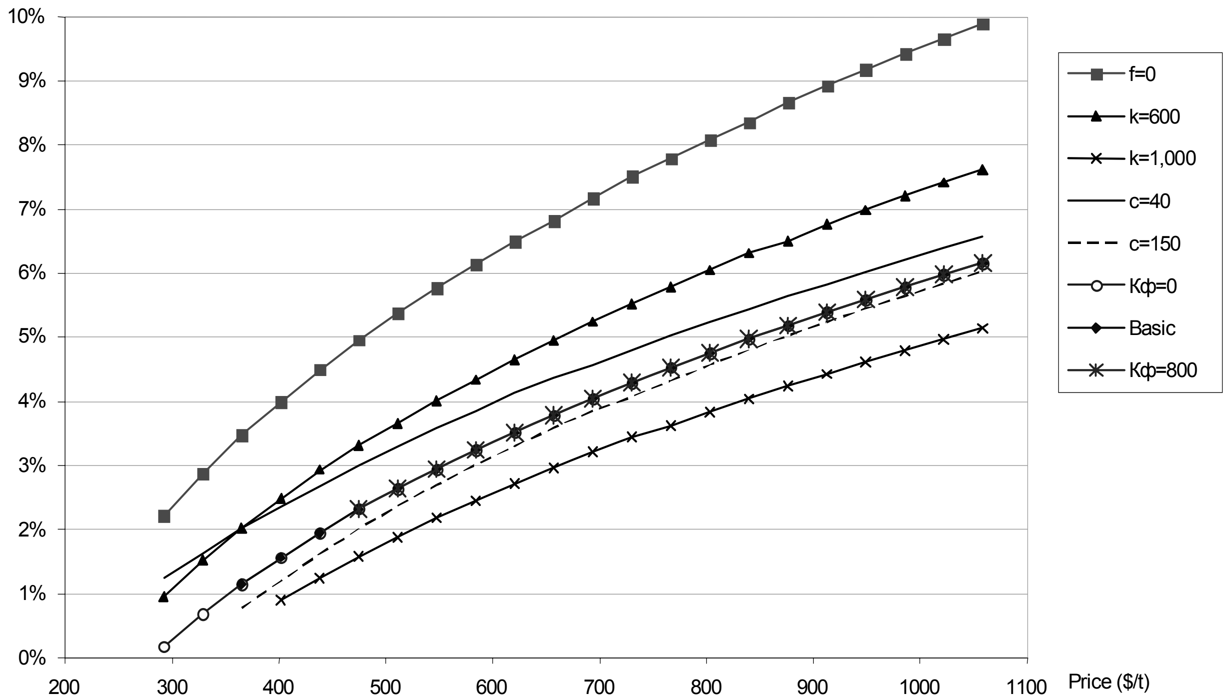

Fig. 10. Optimum recovery rate

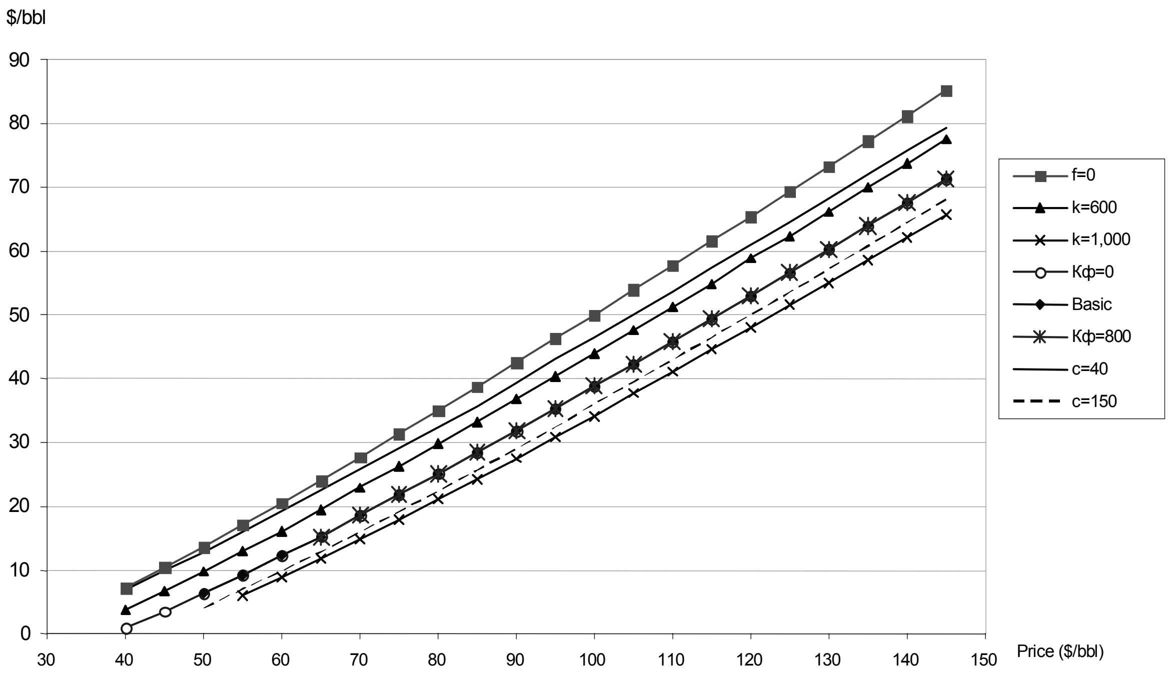

Fig. 11. Optimum tax plus tariff rate totals

Another feature of the $f = 0$ option (alongside with $k = 600$, $K_ф = 0$, and $c = 40$) stems from ability to market oil under p = $40/bbl.

The $k = 1{,}000$ option is only feasible under p = $55/bbl, while $K_ф = 800$ – under p = $65/bbl.

4. CONCLUSIONS

It can be concluded that tax and tariff incentives would be likely unique for different fields, although remaining within a single corridor. Tax rate optimisation should make provisions for oil company response to their tax changes.

5. REFERENCES

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6. BIOGRAPHY

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