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Modeling Inflow Control Devices in Gas Condensate Reservoirs with Reservoir Simulation

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Sylvain Ferro

Modeling Inflow Control Devices in Gas Condensate Reservoirs with Reservoir Simulation

Abstract:

Inflow Control Device (ICD) is a relatively new completion item. The objective of this device is to balance the inflow coming from the reservoir toward the wellbore by introducing an extra pressure drop. ICDs have already been implemented in many oil reservoirs all over the world. The main objective of this thesis is to investigate the possibility of using ICDs in gas condensate reservoirs. This work is without prior studies in literature. Synthetic reservoir data associated with economic calculations were used to carry out this investigation.

A single-well reservoir model combined with a r-z radial grid is developed. This model is based on two non-communicating layers. Different properties are assigned to these layers to generate a desired uneven inflow. This model is run many times with different properties each time (initial reservoir pressure in both layers, dew point pressure in both layer, layer permeability, layer thickness, etc.). This "reservoir mapping" is intended to cover a large spectrum of potential gas condensate reservoirs. ICD is modeled by a skin factor, generating an extra pressure drop, in these reservoirs simulated.

For each reservoir simulated, an optimization process is performed using Nelder Mead Simplex Reflection solver. The objective function for the optimization is Net Present Revenue of the project (also referred to as *Total Discounted Value* in this thesis). Net Present Revenue is derived from economic calculations using as input reservoir simulation results. The only optimization variable is skin value, representing ICD. For each reservoir simulated, a Net Present Revenue comparison is made between cases with no skin and cases with a given skin value (result of optimization process).

This thesis shows that among all cases simulated, only few of them show an increase in Net Present Revenue when using ICDs, and this increase is not significant. Some sensitivity analysis have been performed focusing mainly on two parameters: permeability and layer thickness. These analysis show a high dependency of optimization results on both intrinsic values of these parameters (permeability intrinsic value and layer thickness intrinsic value) and ratios of this parameters (permeability ratio and layer thickness ratio).

The results of this thesis, even if they may lack generality, raise interrogation regarding the relevance of using ICDs in gas condensate reservoirs. No definitive answer can be given yet. Better modeling and further investigations are required. Some possible continuation steps to this study are suggested at the end of this thesis.

Keywords: Inflow Control Devices, Gas Condensate, SENSOR, Pipe-It, Skin, Optimization, Master Project, Slave Project, Sensitivity, Net Present Revenue

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Chapter 1

Introduction

Contents

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1.1 Problem Statement

The main point of this section is to present the thinking process that led to initiating a thesis on this topic.

Current use of Inflow Control Devices

Inflow Control Devices (ICDs) are a rather new type of completion. It is one of the tools used in what is called "advanced completions". The main objective is to improve ultimate reservoir recovery by balancing the inflow coming towards the reservoir from heterogeneous pay zones. In providing a way to avoid bypassing reserves, ICDs are intended to generate some incremental value from a reservoir. ICD technology is becoming mature. It has been implemented in many reservoirs all over the world. However, the current use of ICDs is limited to oil reservoirs. For the time being, almost no extensive investigation has been made to assess alternative implementations of ICDs. Therefore, the idea behind this thesis work is to see if some new implementation opportunities can be found.

Starting point for this Master Thesis

ICD is a proven technology for oil reservoirs, supported by many case studies and reports. Nevertheless, potential benefits of ICDs in gas reservoirs are lacking. The main reason being that an ICD is responsible for an extra pressure drop. Yet, for a gas reservoir, every pressure drop means more wells to be drilled to satisfy the gas contract. Upsides provided by ICDs should balance this major downside. This being said, it is not even sure that ICDs have any advantages for gas reservoirs. Indeed, the problem of water breaking through is completely different in gas reservoirs compared to oil reservoirs. Experience shows that producing water in a gas well "kills" the well. Water breakthrough is more an "on/off"; reducing water production is not relevant here. Moreover, gas has a much higher mobility than oil. Balancing inflow from the reservoir, by adding flow restrictions (ICDs) in highly productive zone, is not likely to work if the gas is so mobile that massive crossflow occurs in the reservoir. All these assertions, even if they are not supported by any further investigation, contributed to drop the idea of using ICDs for gas reservoirs. This is when the idea of using ICDs for gas condensate reservoirs came up. Gas condensate reservoirs, even if they are primarily gas reservoirs, can be considered as "halfway" between oil reservoirs and gas reservoirs because of the substantial revenue derived from condensate production even though that condensate only constitutes a small fraction of the total moles produced.

A further reason for going that way is that, to my knowledge, not a single study has been published in this field so far. The original idea was to simulate two non communicating reservoir layers depleting at the same rate. The reason is that we had the feeling this strategy would maximize the condensate production and therefore maximize Net Present Value (NPV). Eventually this constraint was dropped. On the one hand we did not want to introduce any bias in the study. On the other hand we are interested in NPV and so that must be our objective function. In the following section we explain the way this study is presented.

1.2 Report organization

A short description of ICD technology seems necessary to portray challenges it tries to face and solutions it provides to solve these challenges. Before exposing results from our study and discussing them in detail, we will make a thorough description of simulation model and Pipe-it project architecture. Then, based on results, we will propose some perspectives for further work in this direction. The final section will be dedicated to the main conclusions from this study and to some recommendations for implementing ICDs in Gas Condensate Reservoirs. Additionally, this report includes several appendices. The body of the text aims at being self-sufficient for the target we set ourself. However, it seems useful to provide some extra information such as a description of utilized softwares. To enable any reader to reproduce calculations presented in this report, reservoir model dataset, Pipe-It project, and include files (PVT tables and relative permeability functions) are given just as they are.

Chapter 2

Presentation of ICD technology

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2.3 Different models of Inflow Control Devices 5

In this chapter, we give a short introduction to ICD technology. The point being to contextualize the present study and to show the role played by ICDs in the field of advanced completions. This Chapter is largely inspired from NTNU Semester Project report [Ferro 2009].

2.1 Challenges related to horizontal wells

Horizontal and multilateral wells became over the years a popular practice for field developments. Horizontal wells increase wellbore exposure to reservoir thanks to the extension of horizontal section length compared to a vertical well. As a consequence, pressure drawdown required to achieve the same flowing rate is reduced [Salery 2003b, Salery 2003a]. Such wells proved to increase ultimate recovery, lower the cost per unit length or make the production from thin oil column reservoirs (e.g. the Norwegian Troll field) profitable [Mikkelsen 2005, Madsen 2005]. However, first, there are some practical offsets to benefits provided by horizontal wells such as higher cost for the well or a commercial success rate of lower than 100% (65% in the U.S in 2003) [Joshi 2003]. Then, one should remember that increase in well length and exposure to different reservoir formations present some downsides:

- in highly productive sandstones reservoirs for instance, horizontal wells experience uneven flow profile leading to cresting/coning effects. In general, we observe a so called *Heel to Toe Effect* (*HTE*) which is the tendency to produce more at the heel than at the toe of the well, due to frictional pressure drop. In case of excessive increase of producing rate and/or horizontal length, HTE can lead to a limited sweep efficiency resulting in bypassed reserves [Qudaihy 2003].
- in carbonate reservoirs, HTE is also present but the main challenges are permeability variations and fractures which lead to uneven inflow profile and accelerate water and gas breakthroughs [Raffn 2008].
- annular flow is another challenge often encountered when horizontal wellbores are completed with Stand-Alone-Screens (SAS) or with pre-perforated/Slotted liners (Fig. 2.1).

2.2 Solutions to counteract horizontal well downsides

We just mentioned several challenges inherent to horizontal wells and that need to be mitigated. It exists different ways to achieve this objective:

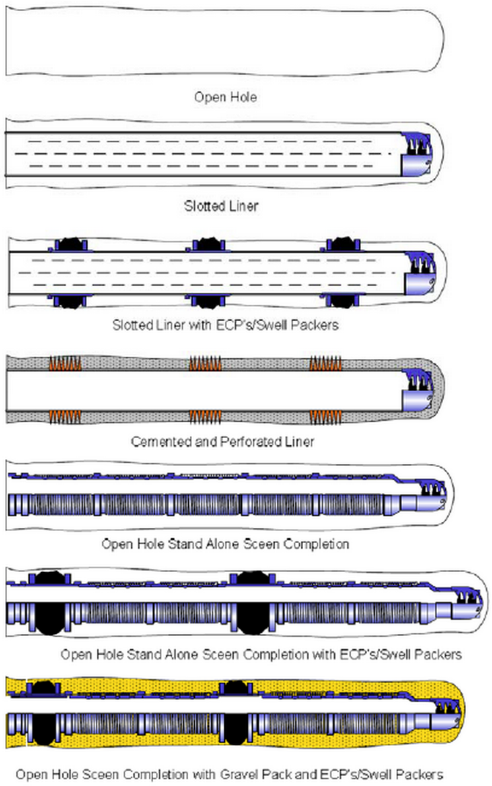

Fig. 2.1: Different Open Hole completion options. ICD is generally associated with sand screens and packers.

- varying perforation density: in order to make the inflow more uniform, one can increase the amount of perforations towards the toe of the well [Landman 1991] (Fig. 2.2).

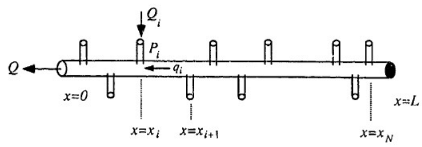

Fig. 2.2: Schematic of horizontal perforation model. In varying Δ x $= x_{i+1} - x_i$, we can make perforation density not uniform and counterbalance uneven inflow [Landman 1991].

- using remotely operated flow restrictions called *Interval Control Valves* (*ICVs*). The principle is to actively control (from surface) inflow coming from different reservoir zones [Al-Khelaiwi 2008].
- using fixed flow restrictions, called ICDs, between the formation and the base pipe. ICD is a relatively new sandface completion mainly for horizontal wells. It is intended to mitigate the previously mentioned downsides by balancing inflows coming from different parts of the reservoir towards the wellbore. ICDs passively equalize the inflow from the (the restriction is set at the time of installation and cannot be changed without recompleting the well) [Al-Khelaiwi 2008].

Inflow Control Devices are the focus of this study. Indeed, perforation density variations lost most of its attractiveness after the arrival of ICVs and ICDs. ICDs are much simpler than ICVs in terms of understanding, principles, and possibilities of implementation in reservoir simulators. That is why we decided to focus on ICDs in this project*. Several models of ICD are currently available in the oil industry as discussed in the next section.

2.3 Different models of Inflow Control Devices

The "original" ICD concept was developed to improve Troll field performance [Henriksen 2006]. The design of this ICD was based on labyrinth channels (Fig. 2.3).

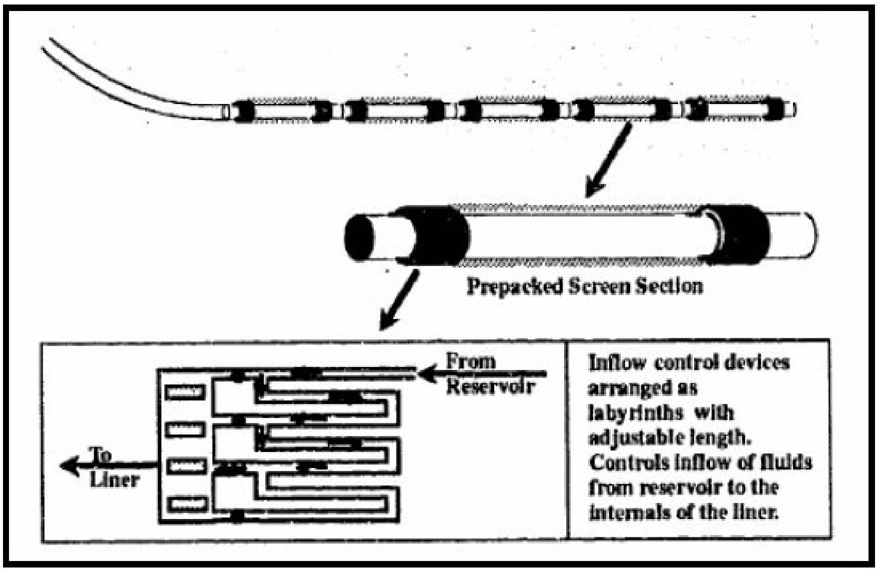

Fig. 2.3: Original design of the ICD based on channels of adjustable length [Alkhelaiwi 2007].

By varying labyrinth's length and diameter it was possible to get the desired pressure drop. Since then, three of the world main suppliers of technology to the oil and gas business have developed their own device to balance the inflow towards the wellbore. Each of these devices is based on a different design (Channels, Nozzles and Orifices) to provide the pressure drop required [Alkhelaiwi 2007].

Channel-type ICD

This ICD integrates a flow channel as main element to impose a uniform pressure distribution along the wellbore (Fig. 2.4).

The inflow regulation is tuned by varying the number of helical channels and their cross-section, depending on reservoir and production requirements. The length and shape of the flow path create resistance to flow that increases as the flow increases [Ratterman 2005]. The fluid flows from the formation to a small annular space by going through several screen layers. Then it flows along the base pipe to the ICD chamber to finally ends into the inner section of the casing. An important advantage of this design based on channels is that the pressure drop occurs on a relatively long interval (compared to orifice-based and nozzle-based ICDs for instance) which reduces significantly the risks of erosion and plugging of ICDs [Alkhelaiwi 2007].

*If the reader wants to have a comparison between passive and active inflow controls and to know more on how to choose between them, he should read [Al-Khelaiwi 2008].

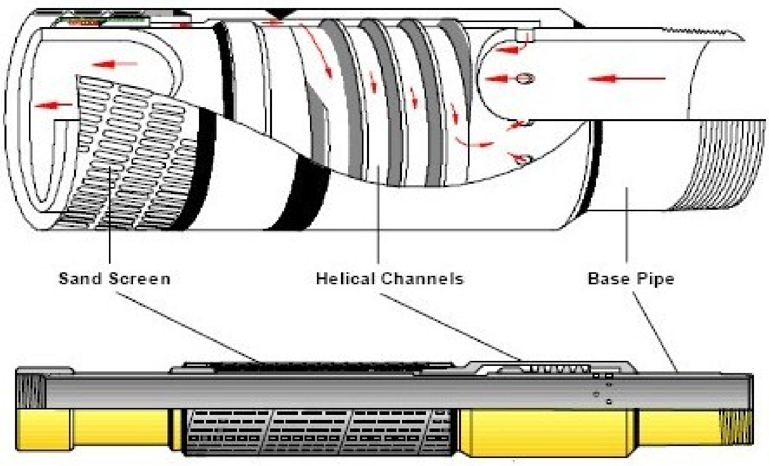

Fig. 2.4: ICD based on channel concept. Helical channels provide required pressure drop [Qudaihy 2003].

Nozzle-type ICD

This ICD uses ceramic nozzles to create the pressure drop that will balance the inflow towards the well. We can see an illustration of this ICD on Fig. 2.5.

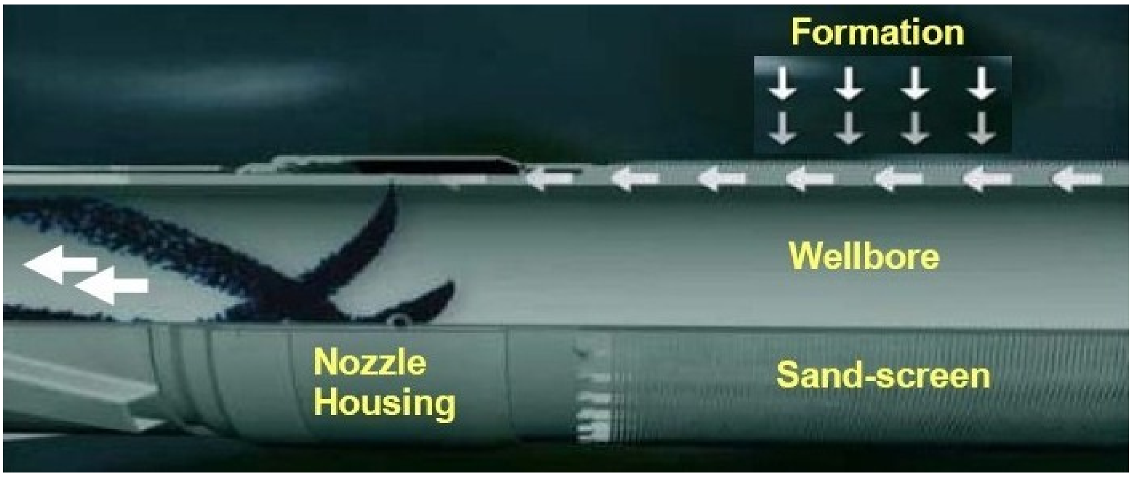

Fig. 2.5: ICD based on nozzle concept. Nozzles perforated in the base pipe provide required pressure drop [Shahri 2009].

Basically, the fluid enters the screen and flows between the axial wires before going along the un-perforated base pipe towards the ICD housing. Then it passes through the nozzles to end into the base pipe [Moen 2005] (Fig. 2.6).

The required pressure drop is obtained by varying the number and diameter of the nozzles. One of the main advantage of using a fluid constriction based on nozzles is that it makes the pressure drop highly dependent on fluid density and velocity and less dependent on viscosity. However, the main downside of this design is erosion due to fluid velocity and even more when combined with sand production [Alkhelaiwi 2007].

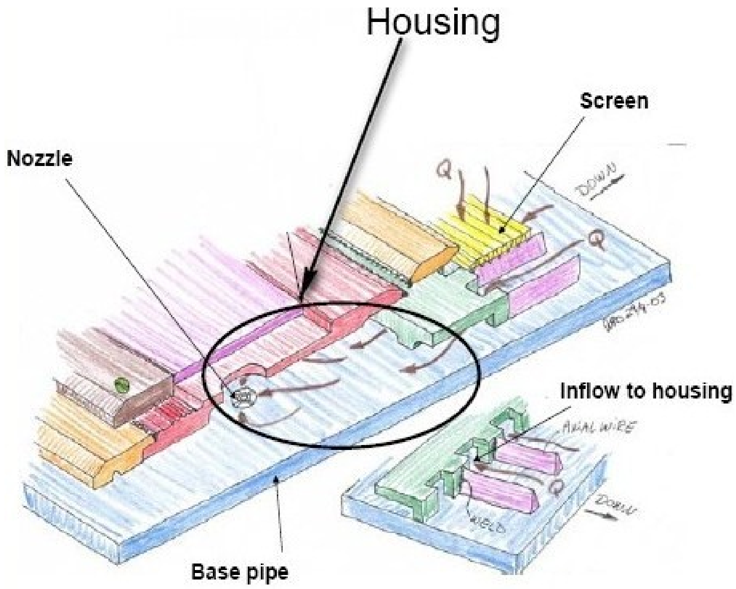

Fig. 2.6: Schematic of the elements included in the nozzle-based ICD [Moen 2005].

Orifice-type ICD

This type of ICD incorporates a given number of orifices of known diameter and flow characteristics. This design is very similar to nozzle-based design. Flow characteristics are expected to be similar. The only main difference compared to nozzle-based ICD is the location of orifices. The orifices are part of the ICD chamber (Fig. 2.7) while the nozzles are perforated directly on the base pipe.

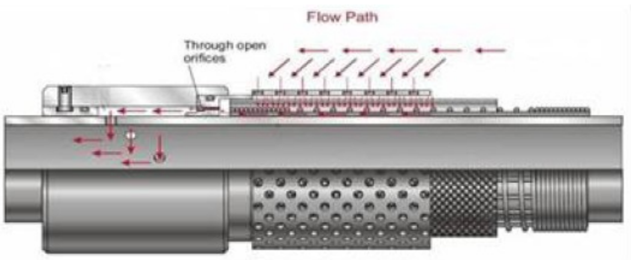

Fig. 2.7: ICD based on orifice concept. Orifices perforated on ICD chamber provide required pressure drop [Alkhelaiwi 2007].

This last feature simply have a minor impact on the value of flow characteristics. The conclusion is while channel-type ICDs and Nozzle-type ICDs are significantly different regarding the concept, Nozzle-type ICDs and Orifice-type ICDs are almost identical regarding the principle [Alkhelaiwi 2007].

Chapter 3

Model Description

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3.1 SENSOR Reservoir Model

As mentioned in Chapter 1, to my knowledge based on an exhaustive literature search, not a single study has been presented regarding ICDs with gas condensate reservoirs. Thus, for this pioneering study we decided to use synthetic data as opposed to real data from a field for instance. The reason is quite simple: before determining if an ICD is suitable for a specific gas condensate reservoir, we should first find out if ICDs are suitable for gas condensate reservoirs at all. To do so, we chose to perform a kind of "reservoir mapping" (this point of view is exposed in details in Section 4.2 of next Chapter). In this section, reservoir model for *Base Case* configuration is described to help the reader understand the framework of this study.

Geometry

The reservoir model is based on a Single-Well Model. This kind of reservoir model makes the use of an r-z radial grid relevant. Dimensions of the reservoir are decided arbitrary. Wellbore radius, r_w , is equal to 0.35 foot (4.2 inches) while the external radius, r_e, is equal to 3000 feet. The reservoir is divided in two geologic layers, *Layer* 1 at the top and *Layer* 2 at the bottom.

Top of the reservoir is located at 10 000 feet. Each reservoir layer thickness is 100 feet high (*Base Case* configuration).

Rock and Fluid Properties

Porosity, ϕ, is constant throughout the reservoir and the value is equal to 30 %. Permeability, K_1 and K_2, in each reservoir zone is constant but different from one another. Indeed, an ICD is designed to balance the inflow coming from the reservoir to the wellbore. If reservoir layers are identical, the inflow from the reservoir will be identical in both layers, and as a consequence using an ICD is not appropriate. Therefore we need to introduce a "contrast" between *Layer* 1 and *Layer* 2. For instance we can introduce a permeability contrast, defined as $\frac{K_1}{K_2}$. The *Base Case* configuration is such that the

Table 3.1: RADIAL MODEL RESERVOIR DESCRIPTION (Base Case)

GEOMETRY		
Surface area, km^2		2.6
Radial grid model		20 x 1 x 2
Well radius (r_w), ft		0.35
External boundary radius (r_e), ft		3000
Radial coordinates, ft		
Thickness, ft	*Layer 1*	100
	Layer 2	100
Depth of top of the reservoir, ft		10000
ROCK AND FLUID PROPERTIES		
Porosity		30%
Horizontal (K_h=K_x=K_y), mD	*Layer 1*	500
	Layer 2	10
Vertical permeability (K_v=K_z), mD		0
Water FVF initial, rb/stb		1.00
Water compressibility, 1/psi		2.67E-06
Water density, lbs/cuft		62.428
Water viscosity, cp		0.50
Rock compressibility, 1/psi		5E-06
Reference pressure for water FVF, psia		7000
RELATIVE PERMEABILITY ANALYTICAL DATA		
Connate water saturation (S_{wc})		0.25
Residual oil saturation to water (S_{orw})		0.25
Residual oil saturation to gas (S_{org})		0.10
Critical gas saturation (S_{gc})		0.00
Rel. perm. of water at S_w=1-S_{orw}, S_g=0 (Kr_{wro})		0.20
Rel. perm. of gas at S_w=S_{wc}, S_g=S_{org} (Kr_{gro})		0.74
Rel. perm. of oil at S_w=1-S_{wc}, S_g=0 (Kr_{ocw})		1.00
Exponent for Kr_w analytical curve (n_w)		3.00
Exponent for Kr_{ow} analytical curve (n_{ow})		3.00
Exponent for Kr_g analytical curve (n_g)		3.00
Exponent for Kr_{og} analytical curve (n_{og})		3.00
INITIAL CONDITIONS		
Initial pressure , psia	*Layer 1*	5000
	Layer 2	5000
Reference depth , ft	*Layer 1*	10050
	Layer 2	10150
Initial dew point pressure at depth , psia	*Layer 1*	3000
	Layer 2	3000
WELL DATA AND CONTROL PARAMETERS		
Skin factor	*Layer 1*	0
	Layer 2	0
Limiting bottom hole pressure, psia		1000
Target well gas rate, Mscf/d		50000
TIME SPECIFICATIONS		
Simulation period, days		7300
Report frequency, period in days	*Year 1*	30, 60, 90, 185
	After year 1	365

permeability contrast is $\frac{K_1}{K_2}$=50. These two layers are non-communicating. The vertical permeability, K_v or K_z, is equal to zero in our model, meaning there is no crossflow between *Layer* 1 and *Layer* 2. Black-Oil characterization was used for this study. [Fevang 2000] showed that when studying depletion cases, black-oil models can be used provided a good care is given to GOR and OGR initializations and PVT data are generated correctly. Thus, compositional models being more complex and using more CPU-time, we preferred using a black-oil model instead. Reservoir fluid properties are taken from a PVT table from [Fevang 1995].

This table gives several PVT parameters values: Formation Volume Factors, B_o and B_g, viscosities, VIS_o and VIS_g, Solution Gas-Oil Ratio, R_s, and Solution Oil-Gas Ratio (more commonly called Condensate Gas Ratio), r_s versus a given set of Saturation Pressure (also called Dew Point pressure), P_{SAT}.

Readers can refer to Appendix C to have a complete overview of the table. Other rock and fluid properties are taken from [Fevang 1995].

Relative Permeability Analytical Data

For relative permeability functions, we decided to use the analytical model, *KRANALYTICAL*, in SENSOR simulator. This model is based on correlations similar to Modified Brooks-Corey (MBC) model. Equations used by SENSOR are:

$$\mathrm{Kr_w} = \mathrm{Kr_{wro}} * \left(\frac{\mathrm{S_w} - \mathrm{S_{wc}}}{1 - \mathrm{S_{orw}} - \mathrm{S_{wc}}}\right)^{\mathrm{n_w}} \tag{3.1}$$

$$\mathrm{Kr_{ow}} = \mathrm{Kr_{ocw}} * \left(\frac{1 - \mathrm{S_{orw}} - \mathrm{S_w}}{1 - \mathrm{S_{orw}} - \mathrm{S_{wc}}}\right)^{\mathrm{n_{ow}}} \tag{3.2}$$

$$\mathrm{Kr}_{og} = \mathrm{Kr_{ocw}} * \left(\frac{1 - \mathrm{S_{org}} - \mathrm{S_{wc}} - \mathrm{S_g}}{1 - \mathrm{S_{orw}} - \mathrm{S_{wc}}}\right)^{\mathrm{n_{og}}} \tag{3.3}$$

$$\mathrm{Kr}_{w} = \mathrm{Kr_{gro}} * \left(\frac{\mathrm{S_g} - \mathrm{S_{gc}}}{1 - \mathrm{S_{org}} - \mathrm{S_{wc}} - \mathrm{S_{gc}}}\right)^{\mathrm{n_w}} \tag{3.4}$$

Correlation parameters values we used for our reservoir model are found in Table 3.1. These values are not randomly chosen but are the result of a match between relative permeability curves produced by SENSOR model and relative permeability curves given by Fevang data [Fevang 1995]. Relative permeability data from Fevang is found in Appendix D. Fig. 3.1 shows these two sets of curves.

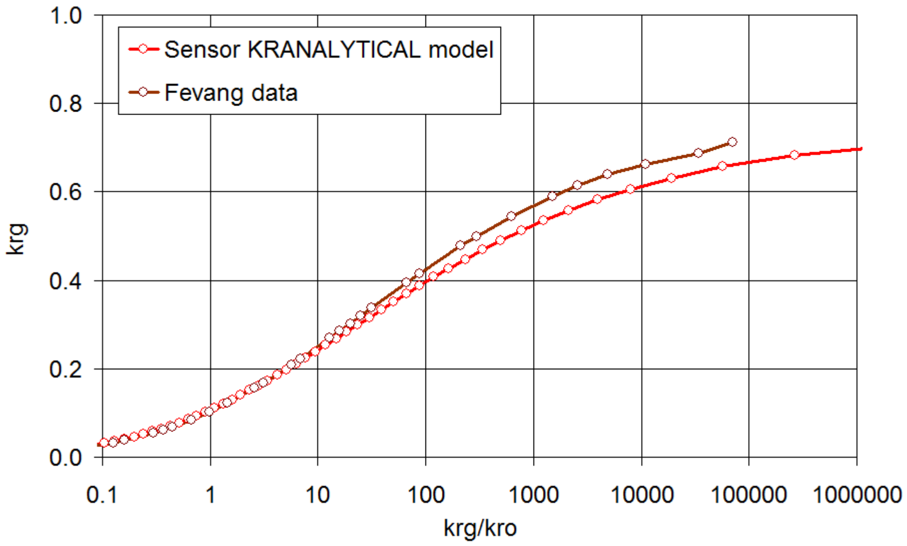
We can see that all plots show consistency between SENSOR analytical model data and Fevang data.

Initial Conditions

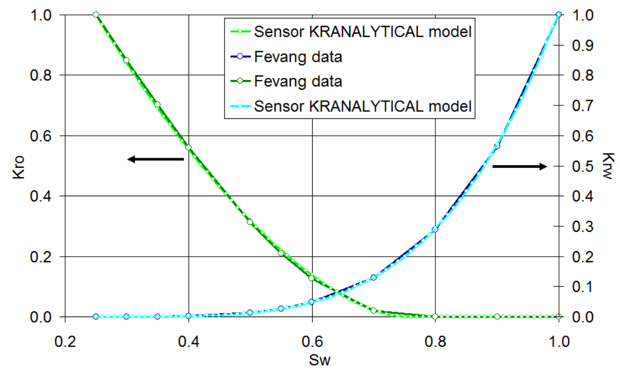
The initial reservoir pressure is the same in both layers (*Base Case* configuration), with 5000 psia initial pressure. Pressure initialization is done in the middle of each layer. Similarly, dew point pressure is the same in both layers (*Base Case* configuration) and equals 3000 psia.

Well Data and Control Parameters

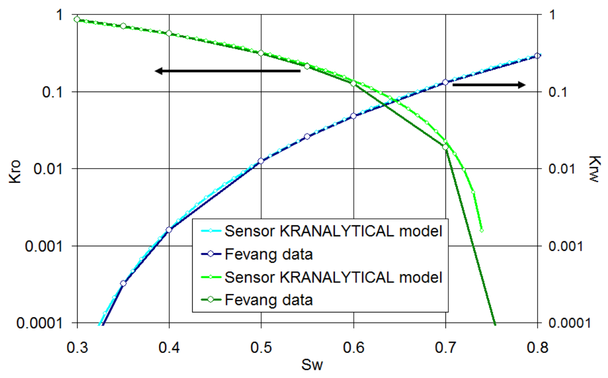
As mentioned before, the reservoir model is a Single-Well Model, as opposed to Full Field Model. This point of view was chosen because the objective of the study is to capture the impact of ICDs on deliverability. We also decided to use a vertical well even if ICDs are currently implemented in



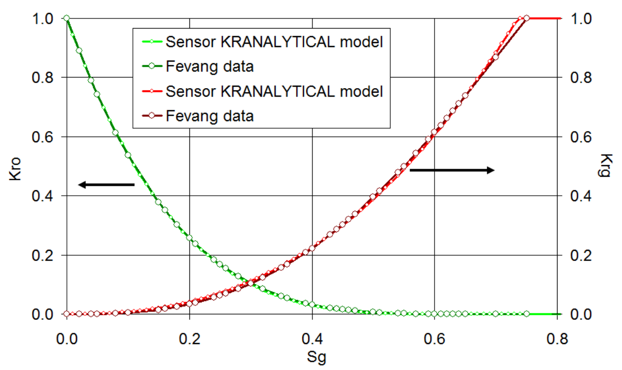
(a) Gas relative permeability versus relative permeability ratio $\frac{Kr_g}{Kr_o}$ on a semi-logarithmic scale.



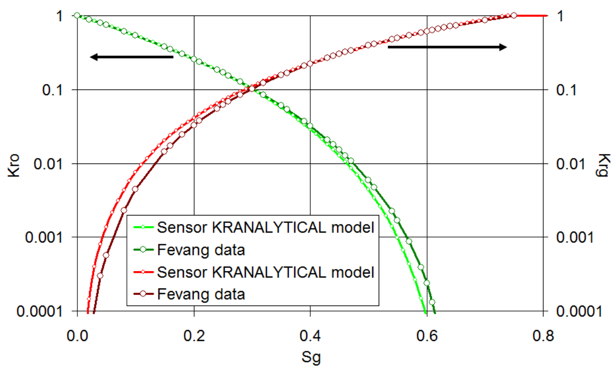
(b) Oil and water relative permeability versus water saturation on a linear scale.



(c) Oil and water relative permeability versus water saturation on a semi-logarithmic scale.



(d) Oil and gas relative permeability versus gas saturation.



(e) Oil and gas relative permeability versus gas saturation on a semi-logarithmic scale.

Fig. 3.1: Relative permeability plots. These plots show a comparison between data measured by Fevang and SENSOR analytical relative permeability model. All results demonstrate a good match for our data, proving that correlation parameters in analytical model for relative permeability functions have the right values.

horizontal well cases. Indeed, in Chapter one of this report, a detailed section is dedicated to the challenges ICDs are trying to tackle:

- Compensate the Heel-To-Toe Effect (HTE)
- Delay the water breakthrough
- Balance the uneven inflow due to permeability variations from different reservoir zones

In the case of a gas condensate reservoir, the main phase flowing inside the wellbore is gas. Yet, in the case of gas the pressure drop due to friction between the heel and the toe of a well is generally not significant. Moreover,in this study we are not taking into account the presence of water, located in an aquifer for instance. The reason is that delaying water breakthrough is not relevant for gas condensate wells. Therefore, we are only studying the possible upside of ICDs in balancing the inflow from two non communicating layers of a reservoir. That is why having two horizontal non communicating layers or two vertical non communicating layers does not change anything for our study.

The production well, named P_1, is perforated in both layers. Skin is introduced in Layer 1. As mentioned earlier and explained in Chapter 2, the effect of ICDs is to create an extra pressure drop between the sandface of the well and the tubing. To represent ICDs, we decided to add a skin in the layer we want to balance the inflow from, i.e. the high permeability layer: *Layer* 1. Introducing a constant skin is a ok surrogate for ICDs, at least for first order calculations. A more realistic ICD model would be to introduce a rate-dependent skin. If we take nozzle-based ICDs for instance, flow follows Bernoulli equation meaning pressure drop due to ICD is proportional to the square of flow rate. An idea would be to use Dq term from the Forchheimer flow model. This possible improvement, with others, will be discussed later in the report.

The well is controlled by a limiting Bottom Hole Pressure (BHP) of 1000 psi. A target rate of 50 000 Mscf/d is defined for well P_1.

Time Specifications

Simulation is run over a period of 20 years. The first time step is forced to be 0.01 day. The following reports come after the first month, third month, sixth month and twelfth month. From the second year, reports are annual until the end of simulation time.

3.2 Pipe-It Project

The main principle behind calculations is explained in Simulation Strategy Description section (Section 4.2). But for a better understanding, we give an outline of our approach before showing how *Pipe-It* capabilities were used. Readers can also find a complete description of software, used for this study and mentioned hereafter, in Appendix A.

3.2.1 Principle

The strategy adopted to build *Pipe-It* project is based on a Master/Slave architecture. Master project consists of initializing the reservoir. Specific values for a given set of properties (initial reservoir pressure in both layers, initial saturation pressure in both layers, permeability in both layers, layer thickness, etc.) are assigned to *SENSOR* data file using *Linkz*. Then, a module inside Master project launches Slave project via *Pipe-Itc*. Slave project is an optimization project using *Reflection* solver.

The objective function is the Total Discounted Value* and the only optimization variable is Skin Value which represents the ICD. Post-processing of results is based on extracting total discounted value for a skin equal to 0 and maximum total discounted value for a given skin value (which can be skin equal to 0 if ICD has no advantage). A percentage of increase in total discounted value between no ICD (skin equal to 0) and ICD is issued to evaluate the potential of implementing ICD. For every reservoir initialization performed in the Master project, an optimization is run in the slave project. Many reservoirs, with different properties, are tested through the Master project to find out which ones are the best candidates for ICD implementation.

3.2.2 Master Project

Master project structure is quite simple (Fig. 3.2). It contains two modules or *Composites* according to *Pipe-It* nomenclature. The first one is in charge of initializing the reservoir using *SENSOR*. The second one launches Slave project using *Pipe-Itc*.

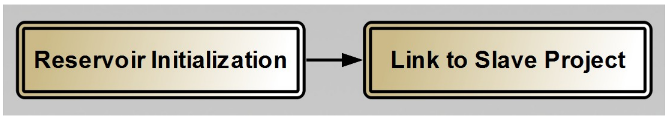
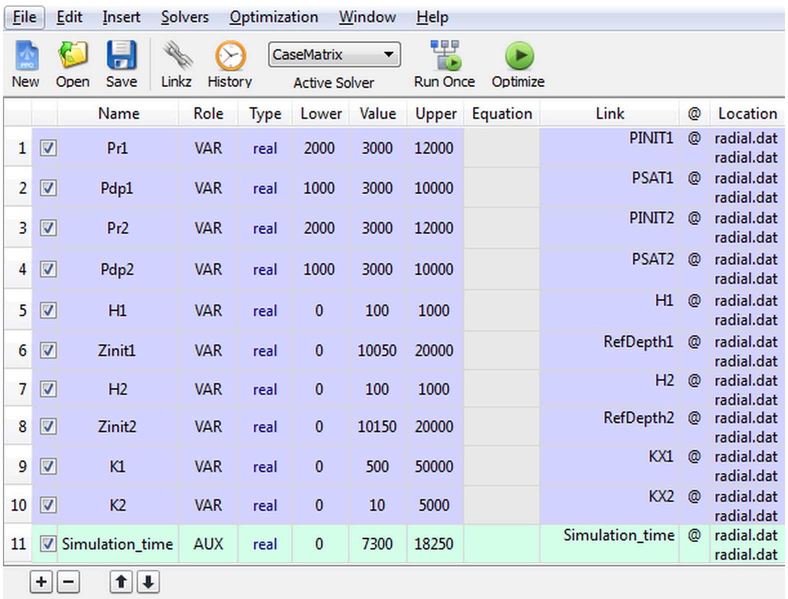


Fig. 3.2: First level of Master project comprising two different composites.

Optimizer GUI

For the initialization to be performed by *SENSOR*, Reservoir properties values must be provided. This is done using the *Optimizer* module of *Pipe-It* (Fig. 3.3).



		Name	Role	Type	Lower	Value	Upper	Equation	Link	@	Location
1	☑	Pr1	VAR	real	2000	3000	12000		PINIT1	@	radial.dat radial.dat
2	☑	Pdp1	VAR	real	1000	3000	10000		PSAT1	@	radial.dat radial.dat
3	☑	Pr2	VAR	real	2000	3000	12000		PINIT2	@	radial.dat radial.dat
4	☑	Pdp2	VAR	real	1000	3000	10000		PSAT2	@	radial.dat radial.dat
5	☑	H1	VAR	real	0	100	1000		H1	@	radial.dat radial.dat
6	☑	Zinit1	VAR	real	0	10050	20000		RefDepth1	@	radial.dat radial.dat
7	☑	H2	VAR	real	0	100	1000		H2	@	radial.dat radial.dat
8	☑	Zinit2	VAR	real	0	10150	20000		RefDepth2	@	radial.dat radial.dat
9	☑	K1	VAR	real	0	500	50000		KX1	@	radial.dat radial.dat
10	☑	K2	VAR	real	0	10	5000		KX2	@	radial.dat radial.dat
11	☑	Simulation_time	AUX	real	0	7300	18250		Simulation_time	@	radial.dat radial.dat

Fig. 3.3: Outline of Pipe-It *Optimizer* used to set up optimizations.

*We talk about Total Discounted Value and not NPV because costs are not included in this study.

Reservoir properties are displayed on Fig. 3.3 and defined in *SENSOR* data file. Several links have been created, using *Linkz* feature, in order to update these variables automatically (Fig. 3.4).

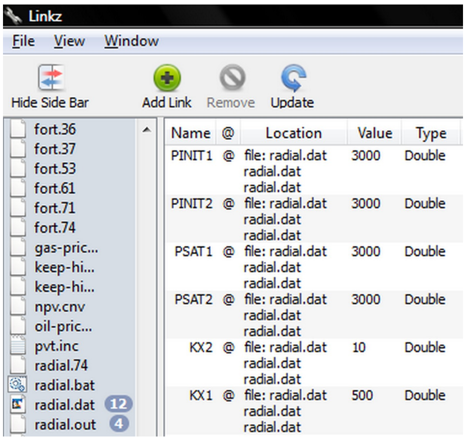
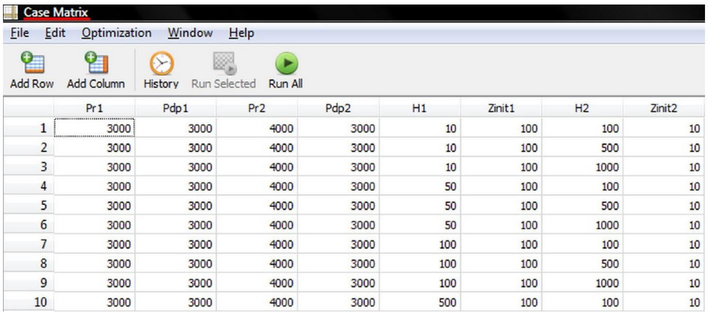


Fig. 3.4: Image of *Linkz* feature (included in Pipe-It) which enables users to locate variables inside files and update them automatically.

Values are assigned to this set of variables using "Excel-like" spreadsheet module, embedded inside Pipe-It, called *Case Matrix* (Fig. 3.5).



	Pr1	Pdp1	Pr2	Pdp2	H1	Zinit1	H2	Zinit2
1	3000	3000	4000	3000	10	100	100	10
2	3000	3000	4000	3000	10	100	500	10
3	3000	3000	4000	3000	10	100	1000	10
4	3000	3000	4000	3000	50	100	100	10
5	3000	3000	4000	3000	50	100	500	10
6	3000	3000	4000	3000	50	100	1000	10
7	3000	3000	4000	3000	100	100	100	10
8	3000	3000	4000	3000	100	100	500	10
9	3000	3000	4000	3000	100	100	1000	10
10	3000	3000	4000	3000	500	100	100	10

Fig. 3.5: "Excel-like" spreadsheet module (included in Pipe-It) called *Case Matrix*. Figure shows an example with variables used for this study.

Reservoir Initialization composite

The optimizer module updates values of variables inside *radial.dat* data file. *Pipe-It* simulator runs SENSOR with those values. As mentioned in previous section, PVT data are defined in an include file called *PVT.inc*. An output file, *radial.out* is created (Fig. 3.6).

Link to Slave Project composite

Once *SENSOR* run is finished in the first composite, *Pipe-It* simulator starts running the second composite. This composite consists only in linking Master and Slave projects (Fig. 3.7).

The scripter called *Optimization including Skin* launches both Slave model (*Slave.ppm*) and Slave optimization module (*Slave.ppo* via a command line using *Pipe-Itc* (Fig. 3.8).

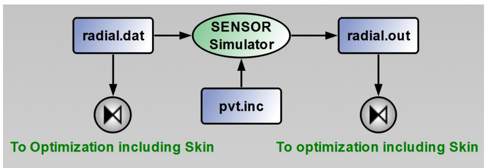


Fig. 3.6: Organization of the inside of Reservoir Initialization composite which launches SENSOR reservoir simulation.

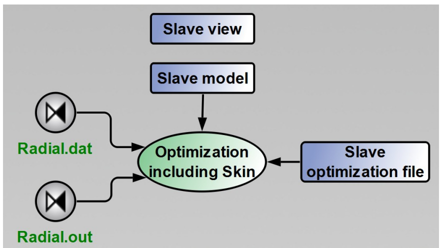


Fig. 3.7: Organization of second composite in Master project, Link to Slave project, triggering Slave project run and optimization.

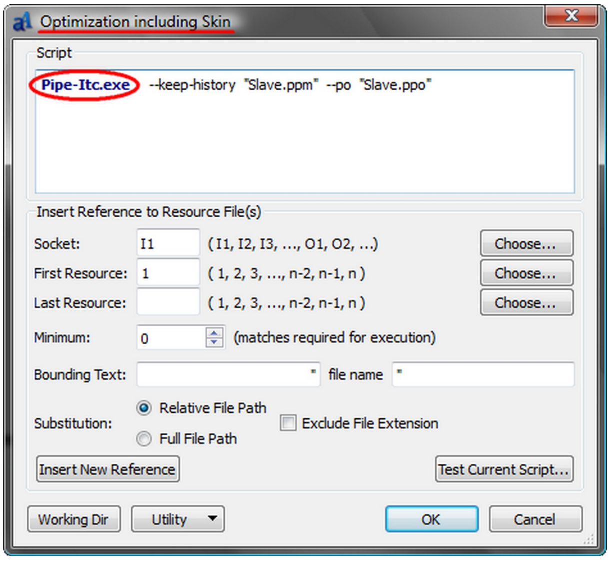


Fig. 3.8: Script associated to Optimization Including Skin process. Using PipeItC, it executes Slave project run and optimization.

3.2.3 Slave project

Slave project structure is more complex than Master. It is divided in 3 composites (Fig. 3.9) each one subdivided also in composites.

Fig. 3.9: First level of Slave project comprising three different composites.

3.2.3.1 Reservoir Simulator composite

Reservoir Simulator composite in Slave project has almost the same structure as the one in Master project (Fig. 3.10). The only difference is the presence of an extra composite called "Convert SENSOR Well Rates by Time Step to Streamz Format" in charge of making SENSOR output results compatible for further treatment by *Streamz*.

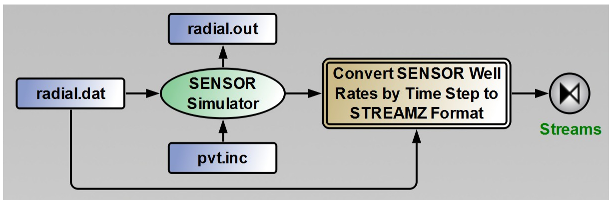


Fig. 3.10: Reservoir Simulator composite which launches SENSOR reservoir simulation and converts SENSOR output into *Streamz* format compatible with Pipe-It.

3.2.3.2 Products Separation composite

This composite is responsible for splitting well stream into two products: Gas and Condensate (Fig. 3.11). Again, a standard Black-Oil characterization is used.

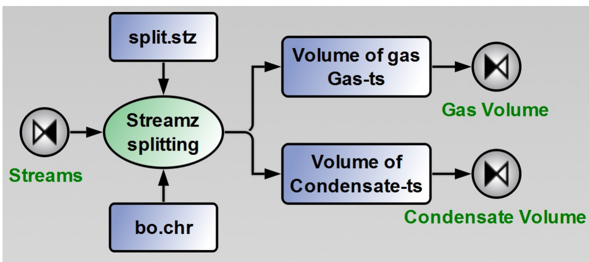


Fig. 3.11: Products Separation composite. Hydrocarbons stream is divided in two streams, Oil stream and Gas stream, using a Black-Oil characterization.

The output of this composite consists of two distinct streams: a volume of gas produced per time step and a volume of condensate produced per time step. The goal is to be able to make further calculations based on values of each product, which are significantly different.

3.2.3.3 Economic Calculations composite

This economic composite is divided in two composites (Fig. 3.12).

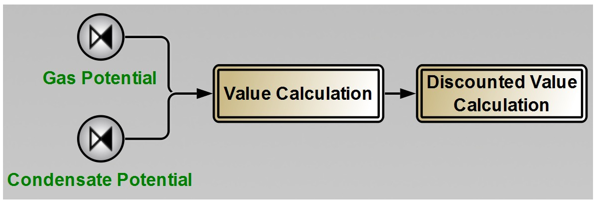


Fig. 3.12: Economic Calculations composite which is itself divided in two sub-composites.

The first composite calculates product values based on given gas and oil prices. But, to get a better consistency in economic calculations, time value of money is introduced. This is performed in the second composite.

Value Calculation

In this composite, gas and condensate values per time step are performed in parallel (Fig. 3.13).

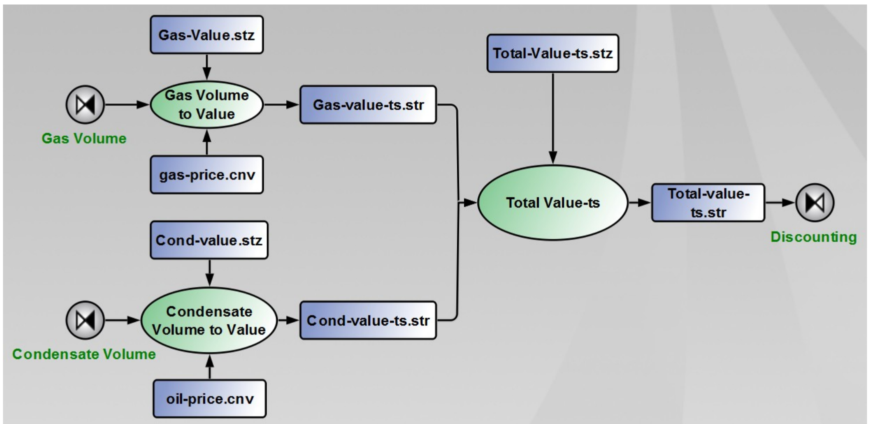


Fig. 3.13: First sub-composite, Value Calculation. Based on price assumptions for oil and gas, it returns a total value (not discounted) per time step called "Total-value-ts.str".

The procedure is identical for both products: value calculations are executed using a price conversion file, "product-price.cnv". Basically a price is entered for each product, then a constant price escalation per year is applied to this price (Table 3.2). This product price conversion file is given in Appendix E.

Table 3.2: VALUE CALCULATION ASSUMPTIONS

Initial oil price	40	\$/bbl
Initial gas price	6	\$/mscf
Price escalation	2.5	%/year

The result is a value for both gas and condensate produced. These values are added to get a total value per time step.

Discounted Value Calculation

The input data entering this composite is a total value per time step not discounted (Fig. 3.14).

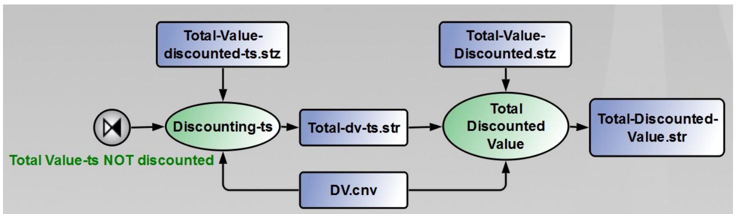


Fig. 3.14: Second sub-composite, Discounted Value Calculation. Given a discount factor value, it calculates the total discounted value of the project which is the objective function for optimization.

Using a discount value conversion file, "DV.cnv" (given in Appendix E), a discount factor is applied to each total value (Table 3.3). It results in a total discounted value per time step. These values for each time step are collated to give a single number which is the total discounted value for the project. This number is the objective function for the optimization and it has to be maximized. One can notice that no cost is included. This is relevant, at least for first order calculations. In this study we are interested in comparing total discounted value for a project with ICD or without ICD. We are not interested in total discounted value itself (it would be different if the point was to compare total discounted values of two completely different projects). Thus, except the error made related to extra costs due to ICD (which is a second order consideration), comparison of total discounted values without including any costs is relevant for our study.

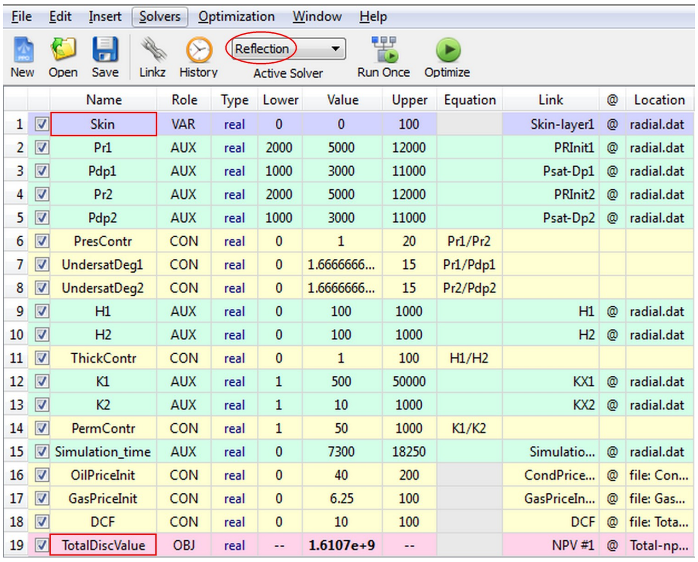
Table 3.3: DISCOUNT VALUE CALCULATION ASSUMPTIONS

Maximum discounting period	50	years
Time increment	1	year
Base case discount factor	30	%/
Maximum discount factor	30	%/
Discount factor increment	1	%/
Interpolation method used	Linear	

3.2.3.4 Optimization process

Optimization process is quite simple (Fig. 3.15). The objective function is total discounted value while the only variable is skin (representing ICD). Auxiliary variables are reservoir parameters defined for each case by Master project. Constraints are related to Economic Calculations: gas price, oil price, and discount factor.

The principle is to use Reflection solver (*Nelder Mead Simplex Reflection solver*) to find out for each reservoir (set of parameters defined in Master project case matrix) which skin value gives the highest total discounted value.



	Name	Role	Type	Lower	Value	Upper	Equation	Link	@	Location
1	Skin	VAR	real	0	0	100		Skin-layer1	@	radial.dat
2	Pr1	AUX	real	2000	5000	12000		PRInit1	@	radial.dat
3	Pdp1	AUX	real	1000	3000	11000		Psat-Dp1	@	radial.dat
4	Pr2	AUX	real	2000	5000	12000		PRInit2	@	radial.dat
5	Pdp2	AUX	real	1000	3000	11000		Psat-Dp2	@	radial.dat
6	PresContr	CON	real	0	1	20	Pr1/Pr2			
7	UndersatDeg1	CON	real	0	1.6666666...	15	Pr1/Pdp1			
8	UndersatDeg2	CON	real	0	1.6666666...	15	Pr2/Pdp2			
9	H1	AUX	real	0	100	1000		H1	@	radial.dat
10	H2	AUX	real	0	100	1000		H2	@	radial.dat
11	ThickContr	CON	real	0	1	100	H1/H2			
12	K1	AUX	real	1	500	50000		KX1	@	radial.dat
13	K2	AUX	real	1	10	1000		KX2	@	radial.dat
14	PermContr	CON	real	1	50	1000	K1/K2			
15	Simulation_time	AUX	real	0	7300	18250		Simulatio...	@	radial.dat
16	OilPriceInit	CON	real	0	40	200		CondPrice...	@	file: Con...
17	GasPriceInit	CON	real	0	6.25	100		GasPriceIn...	@	file: Gas...
18	DCF	CON	real	0	10	100		DCF	@	file: Tota...
19	TotalDiscValue	OBJ	real	--	**1.6107e+9**	--		NPV #1	@	Total-np...

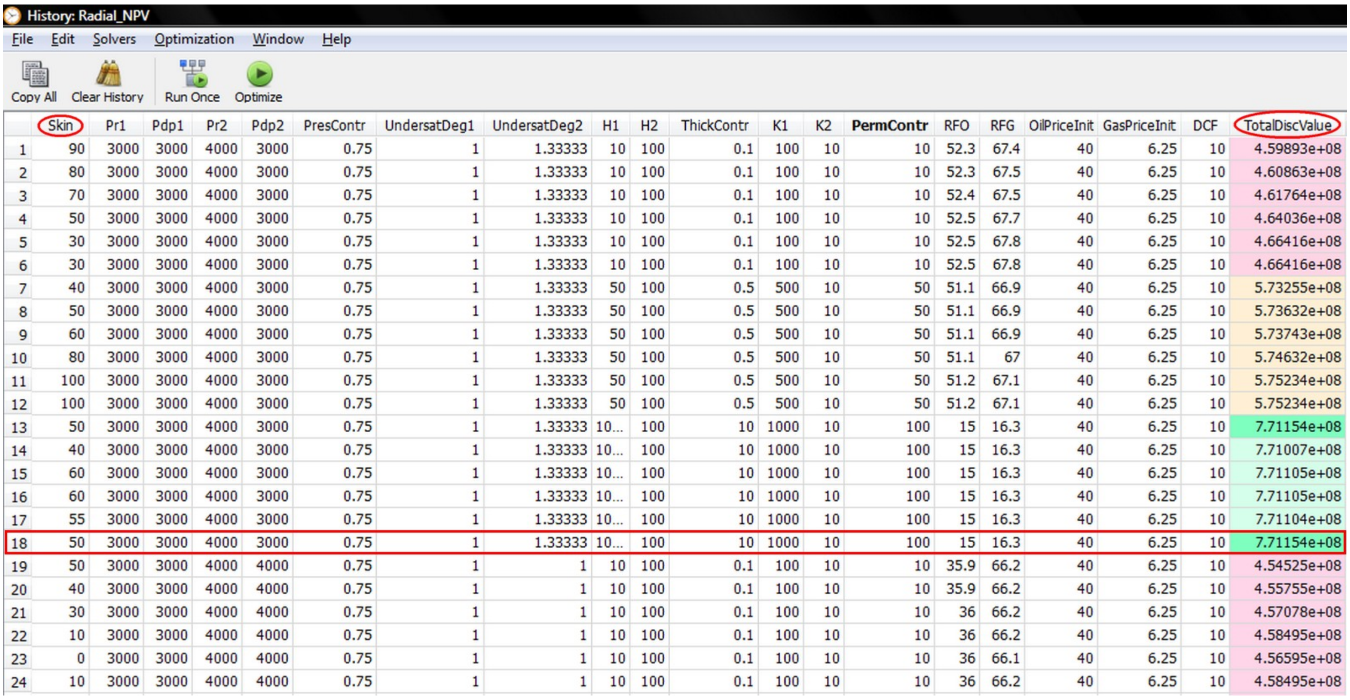
Fig. 3.15: *Optimizer* window showing parameters involved in optimization. Among those, skin is the optimization variable (representing ICD) and Total Discounted Value which is the objective function.

3.3 Results extraction Strategy

Once cases are executed, Pipe-It saves results in a history report (Fig. 3.16). Information related to all variables, auxiliary variables, constraints, and objective function are available. Considering several tens of thousand Slave cases are run, this represents a large amount of information. But only a small fraction of it is interesting. That is why we elaborated a way to extract results of interest.

Basically, this result extraction is based on two Excel macros and a total discounted value comparison. The first macro extracts, for each Master case, the Slave case corresponding to skin equal zero. The second macro extracts, for each Master case, the Slave case with the best total discounted value (as a result of reflection optimization) corresponding to a given skin. Then a comparison is made, for each Master case, between these two total discounted value. A percentage of increase from total discounted value for skin equals to zero to best total discounted value is calculated:

$$\text{TotDiscVal Difference} = \frac{\text{TotDiscVal}_{Max} - \text{TotDiscVal}_{Skin=0}}{\text{TotDiscVal}_{Max}} * 100 \tag{3.5}$$



History: Radial_NPV

File Edit Solvers Optimization Window Help

Copy All Clear History Run Once Optimize

	Skin	Pr1	Pdp1	Pr2	Pdp2	PresContr	UndersatDeg1	UndersatDeg2	H1	H2	ThickContr	K1	K2	**PermContr**	RFO	RFG	OilPriceInit	GasPriceInit	DCF	TotalDiscValue
1	90	3000	3000	4000	3000	0.75	1	1.33333	10	100	0.1	100	10	10	52.3	67.4	40	6.25	10	4.59893e+08
2	80	3000	3000	4000	3000	0.75	1	1.33333	10	100	0.1	100	10	10	52.3	67.5	40	6.25	10	4.60863e+08
3	70	3000	3000	4000	3000	0.75	1	1.33333	10	100	0.1	100	10	10	52.4	67.5	40	6.25	10	4.61764e+08
4	50	3000	3000	4000	3000	0.75	1	1.33333	10	100	0.1	100	10	10	52.5	67.7	40	6.25	10	4.64036e+08
5	30	3000	3000	4000	3000	0.75	1	1.33333	10	100	0.1	100	10	10	52.5	67.8	40	6.25	10	4.66416e+08
6	30	3000	3000	4000	3000	0.75	1	1.33333	10	100	0.1	100	10	10	52.5	67.8	40	6.25	10	4.66416e+08
7	40	3000	3000	4000	3000	0.75	1	1.33333	50	100	0.5	500	10	50	51.1	66.9	40	6.25	10	5.73255e+08
8	50	3000	3000	4000	3000	0.75	1	1.33333	50	100	0.5	500	10	50	51.1	66.9	40	6.25	10	5.73632e+08
9	60	3000	3000	4000	3000	0.75	1	1.33333	50	100	0.5	500	10	50	51.1	66.9	40	6.25	10	5.73743e+08
10	80	3000	3000	4000	3000	0.75	1	1.33333	50	100	0.5	500	10	50	51.1	67	40	6.25	10	5.74632e+08
11	100	3000	3000	4000	3000	0.75	1	1.33333	50	100	0.5	500	10	50	51.2	67.1	40	6.25	10	5.75234e+08
12	100	3000	3000	4000	3000	0.75	1	1.33333	50	100	0.5	500	10	50	51.2	67.1	40	6.25	10	5.75234e+08
13	50	3000	3000	4000	3000	0.75	1	1.33333	10...	100	10	1000	10	100	15	16.3	40	6.25	10	7.71154e+08
14	40	3000	3000	4000	3000	0.75	1	1.33333	10...	100	10	1000	10	100	15	16.3	40	6.25	10	7.71007e+08
15	60	3000	3000	4000	3000	0.75	1	1.33333	10...	100	10	1000	10	100	15	16.3	40	6.25	10	7.71105e+08
16	60	3000	3000	4000	3000	0.75	1	1.33333	10...	100	10	1000	10	100	15	16.3	40	6.25	10	7.71105e+08
17	55	3000	3000	4000	3000	0.75	1	1.33333	10...	100	10	1000	10	100	15	16.3	40	6.25	10	7.71104e+08
18	50	3000	3000	4000	3000	0.75	1	1.33333	10...	100	10	1000	10	100	15	16.3	40	6.25	10	7.71154e+08
19	50	3000	3000	4000	4000	0.75	1	1	10	100	0.1	100	10	10	35.9	66.2	40	6.25	10	4.54525e+08
20	40	3000	3000	4000	4000	0.75	1	1	10	100	0.1	100	10	10	35.9	66.2	40	6.25	10	4.55755e+08
21	30	3000	3000	4000	4000	0.75	1	1	10	100	0.1	100	10	10	36	66.2	40	6.25	10	4.57078e+08
22	10	3000	3000	4000	4000	0.75	1	1	10	100	0.1	100	10	10	36	66.2	40	6.25	10	4.58495e+08
23	0	3000	3000	4000	4000	0.75	1	1	10	100	0.1	100	10	10	36	66.1	40	6.25	10	4.56595e+08
24	10	3000	3000	4000	4000	0.75	1	1	10	100	0.1	100	10	10	36	66.2	40	6.25	10	4.58495e+08

Fig. 3.16: Outline of *History* report structure. It shows simulation results which can be exported to an Excel spreadsheet for instance. Last column is objective function results (best result being in bold font).

Chapter 4

Results and Discussion

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Before executing simulations on a large scale, it is important to check the validity of our model.

4.1 Model Consistency

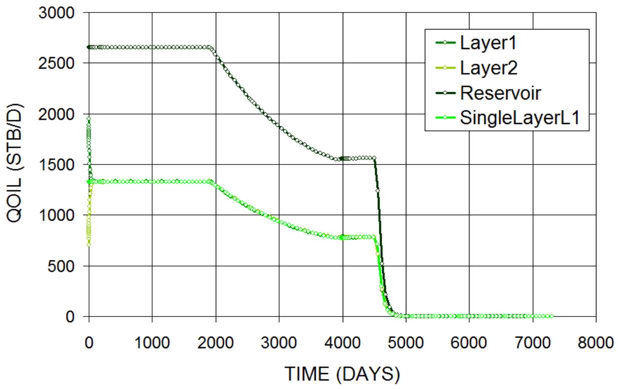
First, we need to verify we built our reservoir model properly.

4.1.1 Reservoir Model

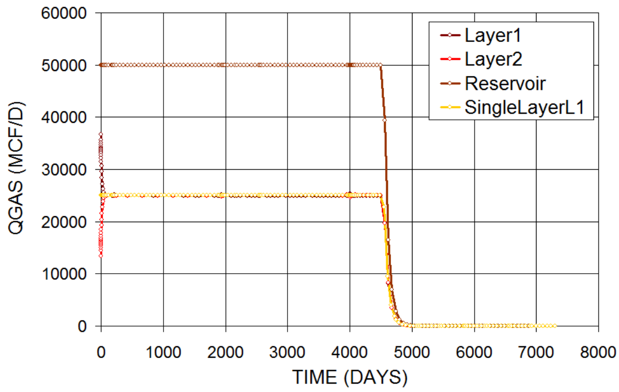
We need to verify that we built our reservoir model properly. To do so, we used the *Base Case* configuration presented in Table 3.1. First, some simple features were checked: such as gas rate plateau corresponding to target rate, or GOR behavior in accordance with depletion profile. But, our main task was to verify that layers 1 and 2 behave identically and independently. Using data collected from SENSOR output file we made several plots presented in Fig. 4.1.

Basic review

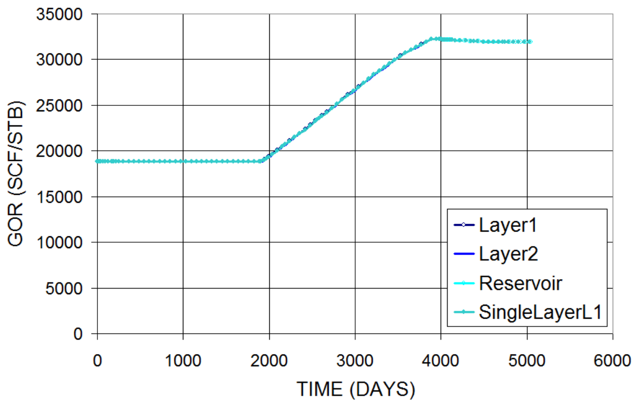
Fig 4.1(b) shows that plateau value from well P1 is equal to 50 000 mcf/d corresponding to entered target rate. Fig. 4.1(c) GOR shows also a standard behavior. Indeed, until reservoir pressure drops below dew point pressure (after 2000 days of simulation), producing GOR is constant. Then, some condensate starts dropping inside the reservoir (the "heavy-ends" first). this condensate is not mobile enough to be produced and mainly stays inside the reservoir. This causes GOR to increase as less condensate is produced at the surface. The last part, with a constant GOR again, is more difficult to interpret. However we can question the pertinence of a ratio calculated with both numerator and denominator close to zero (Fig. 4.1(a) and Fig. 4.1(b)).



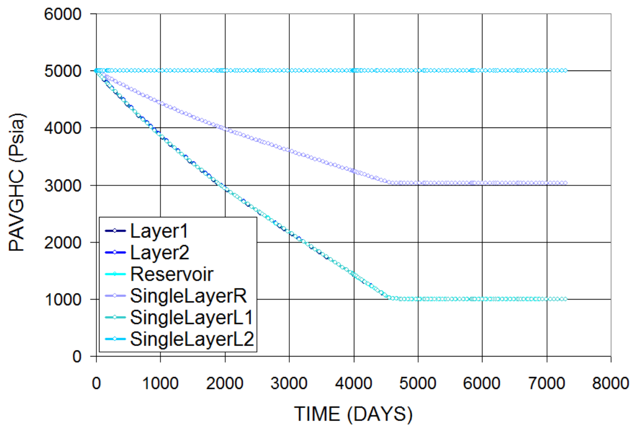
(a) Oil rates produced from different reservoir zones.



(b) Gas rates produced from different reservoir zones.



(c) Production Gas Oil Ratio from different reservoir zones.



(d) Hydrocarbon Average Pressure from different reservoir zones.

Fig. 4.1: Different plots giving evidence of reservoir model consistency. All plots show that Layer 1 and 2 behave identically (consistent reservoir equilibration) and independently (consistent layered no crossflow model). Plot labels description is provided in Table 4.1 and Table 4.2.

Table 4.1: IDENTICAL BEHAVIOR ANALYSIS ASSUMPTIONS

<u>WELL PARAMETERS</u>		
Target rate		50 000 mcf/d
Perforations	*Layer 1*	OPEN
	Layer 2	OPEN
<u>PLOT LABELS</u>		
Layer1		vectors associated to layer 1
Layer2		vectors associated to layer 2
Reservoir		vectors associated to whole reservoir (limited to well P1 in our single well model)

Investigation on identical behavior of both layers

Assumptions used for this analysis are presented in Table 4.1.

All plots of Fig. 4.1 show that layer 1 and layer 2 are identical since plots labeled "Layer 1" and those labeled "Layer 2" coincide. This demonstrates that layer initialization process was performed correctly.

Investigation on independent behavior of both layers

Assumptions used for this analysis are presented in Table 4.2.

Table 4.2: INDEPENDENT BEHAVIOR ANALYSIS ASSUMPTIONS

WELL PARAMETERS		
Target rate		25 000 mcf/d
Perforations	*Layer 1*	OPEN
	Layer 2	CLOSE
PLOT LABELS		
SingleLayerL1		vectors associated to layer 1 with single layer production
SingleLayerL2		vectors associated to layer 2 with single layer production
SingleLayerR		vectors associated to whole with single layer production

Here, we focused on proving that layers behave independently in accord with the layered mo crossflow model we built. To do so, we executed the same reservoir model with layer 2 perforations closed. Since production is coming from layer 1 only, we divided target rate by a factor two (25 000 mcf/d). Fig. 4.1(d) is a good indication of what is happening. Layer 2 is not depleted (pressure remains equal to initial pressure) in conformity to no crossflow allowed between layer 1 and 2. Layer 1 is depleted exactly the same way as layer 1 was depleted when both layers were producing. Pressure drop in the reservoir at the end of simulation (20 years) is half reservoir pressure drop when both layers were producing. The other plots of Fig. 4.1 confirm this analysis.

All these results attest that our reservoir model behaves as expected.

4.1.2 Pipe-It Project

It seems also important to check the validity of calculations and conversions performed in Pipe-It. To do so, we decided to set up manual calculations (using Excel) reproducing exactly what is done in our Pipe-It project. The first step is to take as input for excel calculations, output data from SENSOR simulation runs (Fig. 4.2).

The only data we need for that are oil rates and gas rates per time step. Then we can jump to the second step which is calculating values associated to these rates (Fig. 4.3).

Given an initial product price (oil or gas), every year we proceed to a price increase of 2.5 %. But to take into account time-value of money, we need to introduce discounting. This leads us to the third step of our manual check. Given a discount factor (DCF) value is selected, discounted value per time step is calculated as described in Eq. 4.1.

Oil Rates per Time Step											
Pr1=10 000Psi		Pdp1=6000Psi		Pr2=10 000Psi		Pdp2=6000	K1=500mD		K2=10mD	H1=H2=50	Qtarget=50 000Mcf/d
Skin=0		Skin=20		Skin= 40		Skin=60		Skin=80		Skin=100	
X	Y	X	Y	X	Y	X	Y	X	Y	X	Y
TIME (DAYS)	QOIL (STB/D)	TIME (DAYS)	QOIL (STB/D)	TIME (DAYS)	QOIL (STB/D)	TIME (DAYS)	QOIL (STB/D)	TIME (DAYS)	QOIL (STB/D)	TIME (DAYS)	QOIL (STB/D)
0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8
0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8
0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8	0.0	8900.8
0.1	8900.8	0.1	8900.8	0.1	8900.8	0.1	8900.8	0.1	8900.8	0.0	8900.8
0.1	8900.8	0.1	8900.8	0.1	8900.8	0.1	8900.8	0.1	8900.8	0.1	8900.8
0.2	8900.8	0.2	8900.8	0.2	8900.8	0.2	8900.8	0.1	8900.8	0.1	8900.8
0.3	8900.8	0.3	8900.8	0.3	8900.8	0.3	8900.8	0.2	8900.8	0.2	8900.8
0.5	8900.8	0.5	8900.8	0.5	8900.8	0.4	8900.8	0.3	8900.8	0.3	8900.8
0.7	8900.8	0.7	8900.8	0.7	8900.8	0.6	8900.8	0.5	8900.8	0.4	8900.8
1.1	8900.8	1.1	8900.8	1.1	8900.8	0.9	8900.8	0.7	8900.8	0.6	8900.8
1.7	8900.8	1.7	8900.8	1.7	8900.8	1.3	8900.8	1.1	8900.8	1.0	8900.8
2.6	8900.8	2.6	8900.8	2.6	8900.8	2.0	8900.8	1.7	8900.8	1.4	8900.8
3.9	8900.8	3.9	8900.8	3.9	8900.8	3.1	8900.8	2.5	8900.8	2.2	8900.8
5.8	8900.8	5.8	8900.8	5.8	8900.8	4.6	8900.8	3.8	8900.8	3.3	8900.8
8.7	8900.8	8.7	8900.8	8.7	8900.8	6.9	8900.8	5.7	8900.8	4.9	8900.8
13.1	8900.8	13.1	8900.8	13.1	8900.8	10.3	8900.8	8.5	8900.8	7.4	8900.8
19.7	8900.8	19.7	8900.8	19.7	8900.8	15.5	8900.8	12.7	8900.8	11.0	8900.8

(a) Oil volume produced per time step (from SENSROR output file).

Gas Rates per Time Step											
Pr1=10 000Psi		Pdp1=6000Psi		Pr2=10 000Psi		Pdp2=6000	K1=500mD		K2=10mD	H1=H2=50	Qtarget=50 000Mcf/d
Skin=0		Skin=20		Skin= 40		Skin=60		Skin=80		Skin=100	
X	Y	X	Y	X	Y	X	Y	X	Y	X	Y
TIME (DAYS)	QGAS (MCF/D)	TIME (DAYS)	QGAS (MCF/D)	TIME (DAYS)	QGAS (MCF/D)	TIME (DAYS)	QGAS (MCF/D)	TIME (DAYS)	QGAS (MCF/ D)	TIME (DAYS)	QGAS (MCF/ D)
0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0
0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0
0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0	0.0	50000.0
0.1	50000.0	0.1	50000.0	0.1	50000.0	0.1	50000.0	0.1	50000.0	0.0	50000.0
0.1	50000.0	0.1	50000.0	0.1	50000.0	0.1	50000.0	0.1	50000.0	0.1	50000.0
0.2	50000.0	0.2	50000.0	0.2	50000.0	0.2	50000.0	0.1	50000.0	0.1	50000.0
0.3	50000.0	0.3	50000.0	0.3	50000.0	0.3	50000.0	0.2	50000.0	0.2	50000.0
0.5	50000.0	0.5	50000.0	0.5	50000.0	0.4	50000.0	0.3	50000.0	0.3	50000.0
0.7	50000.0	0.7	50000.0	0.7	50000.0	0.6	50000.0	0.5	50000.0	0.4	50000.0
1.1	50000.0	1.1	50000.0	1.1	50000.0	0.9	50000.0	0.7	50000.0	0.6	50000.0
1.7	50000.0	1.7	50000.0	1.7	50000.0	1.3	50000.0	1.1	50000.0	1.0	50000.0
2.6	50000.0	2.6	50000.0	2.6	50000.0	2.0	50000.0	1.7	50000.0	1.4	50000.0
3.9	50000.0	3.9	50000.0	3.9	50000.0	3.1	50000.0	2.5	50000.0	2.2	50000.0
5.8	50000.0	5.8	50000.0	5.8	50000.0	4.6	50000.0	3.8	50000.0	3.3	50000.0
8.7	50000.0	8.7	50000.0	8.7	50000.0	6.9	50000.0	5.7	50000.0	4.9	50000.0
13.1	50000.0	13.1	50000.0	13.1	50000.0	10.3	50000.0	8.5	50000.0	7.4	50000.0
19.7	50000.0	19.7	50000.0	19.7	50000.0	15.5	50000.0	12.7	50000.0	11.0	50000.0

(b) Gas volume produced per time step (from SENSROR output file).

Fig. 4.2: Excel tables showing data (taken from SENSOR output file) that will be used for manual check of Pipe-It results. Several runs are executed using different skin values.

Initial Oil Price	40 USD															
Price evolution	0.025 per year															
Days	365	730	1095	1460	1825	2190	2555	2920	3650	4015	4380	4745	5110	5475	5840	6205
Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16

Oil Value per Time Step

Skin=0		Skin=20		Skin= 40		Skin=60		Skin=80		Skin=100	
X	Y	X	Y	X	Y	X	Y	X	Y	X	Y
TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)
0.0		0.0		0.0		0.0		0.0		0.0	
0.0	3560.3	0.0	3560.3	0.0	3560.3	0.0	3560.3	0.0	3560.3	0.0	3560.3
0.0	5340.5	0.0	5340.5	0.0	5340.5	0.0	4201.2	0.0	3453.5	0.0	2990.7
0.0	8010.8	0.0	8010.8	0.0	8010.8	0.0	6301.8	0.0	5198.1	0.0	4486.0
0.1	12033.9	0.1	12033.9	0.1	12033.9	0.1	9470.5	0.1	7761.5	0.0	6729.0
0.1	18015.3	0.1	18015.3	0.1	18015.3	0.1	14205.7	0.1	11677.9	0.1	10111.4
0.2	27023.0	0.2	27023.0	0.2	27023.0	0.2	21255.2	0.1	17481.3	0.1	15167.0
0.3	40552.2	0.3	40552.2	0.3	40552.2	0.3	31936.2	0.2	26275.3	0.2	22715.0
0.5	60846.2	0.5	60846.2	0.5	60846.2	0.4	47886.5	0.3	39377.3	0.3	34108.0
0.7	91251.4	0.7	91251.4	0.7	91251.4	0.6	71847.6	0.5	59030.4	0.4	51126.4
1.1	136859.4	1.1	136859.4	1.1	136859.4	0.9	107771.4	0.7	88616.8	0.6	76689.7
1.7	205324.6	1.7	205324.6	1.7	205324.6	1.3	161639.3	1.1	132871.8	1.0	115070.1
2.6	307933.6	2.6	307933.6	2.6	307933.6	2.0	242459.0	1.7	199343.3	1.4	172605.1
3.9	461953.7	3.9	461953.7	3.9	461953.7	3.1	363688.4	2.5	298961.5	2.2	258872.1
5.8	692912.8	5.8	692912.8	5.8	692912.8	4.6	545514.8	3.8	448495.7	3.3	388361.6
8.7	1039369.2	8.7	1039369.2	8.7	1039369.2	6.9	818307.9	5.7	672761.3	4.9	582506.7
13.1	1559036.0	13.1	1559036.0	13.1	1559036.0	10.3	1227426.2	8.5	1009070.7	7.4	873742.3

(a) Oil value per time step calculated using oil rates given in SENSOR output file.

Initial Gas Price	6.25 USD															
Price evolution	0.025 per year															
Days	365	730	1095	1460	1825	2190	2555	2920	3650	4015	4380	4745	5110	5475	5840	6205
Years	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16

Gas Value per Time Step

Skin=0		Skin=20		Skin= 40		Skin=60		Skin=80		Skin=100	
X	Y	X	Y	X	Y	X	Y	X	Y	X	Y
TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)	TIME (DAYS)	Value (USD)
0.0		0.0		0.0		0.0		0.0		0.0	
0.0	3125.0	0.0	3125.0	0.0	3125.0	0.0	3125.0	0.0	3125.0	0.0	3125.0
0.0	4687.5	0.0	4687.5	0.0	4687.5	0.0	3687.5	0.0	3031.3	0.0	2625.0
0.0	7031.3	0.0	7031.3	0.0	7031.3	0.0	5531.3	0.0	4562.5	0.0	3937.5
0.1	10562.5	0.1	10562.5	0.1	10562.5	0.1	8312.5	0.1	6812.5	0.0	5906.3
0.1	15812.5	0.1	15812.5	0.1	15812.5	0.1	12468.8	0.1	10250.0	0.1	8875.0
0.2	23718.8	0.2	23718.8	0.2	23718.8	0.2	18656.3	0.1	15343.8	0.1	13312.5
0.3	35593.8	0.3	35593.8	0.3	35593.8	0.3	28031.3	0.2	23062.5	0.2	19937.5
0.5	53406.3	0.5	53406.3	0.5	53406.3	0.4	42031.3	0.3	34562.5	0.3	29937.5
0.7	80093.8	0.7	80093.8	0.7	80093.8	0.6	63062.5	0.5	51812.5	0.4	44875.0
1.1	120125.0	1.1	120125.0	1.1	120125.0	0.9	94593.8	0.7	77781.3	0.6	67312.5
1.7	180218.8	1.7	180218.8	1.7	180218.8	1.3	141875.0	1.1	116625.0	1.0	101000.0
2.6	270281.3	2.6	270281.3	2.6	270281.3	2.0	212812.5	1.7	174968.8	1.4	151500.0
3.9	405468.8	3.9	405468.8	3.9	405468.8	3.1	319218.8	2.5	262406.3	2.2	227218.8
5.8	608187.5	5.8	608187.5	5.8	608187.5	4.6	478812.5	3.8	393656.3	3.3	340875.0
8.7	912281.3	8.7	912281.3	8.7	912281.3	6.9	718250.0	5.7	590500.0	4.9	511281.3
13.1	1368406.3	13.1	1368406.3	13.1	1368406.3	10.3	1077343.8	8.5	885687.5	7.4	766906.3

(b) Gas value per time step calculated using oil rates given in SENSOR output file.

Fig. 4.3: Excel tables reproducing what is performed in "Value Calculations" composite in Pipe-It project.

$$\text{Discounted Value}_{\,per\ ts} = \frac{\text{Value}_{\,per\ ts}}{(1+\text{DCF})^{\frac{\text{time}}{365}}} \tag{4.1}$$

Results of this discounting are displayed in Fig. 4.4(a). Once it is done, we can merge these values to get a single value called "Total Discounted Value" (Fig. 4.4(b)). For each case, i.e. each skin value, we get a total discounted value.

Discount Factor 10%

Discounted Value per Time Step											
Skin=0		Skin=20		Skin= 40		Skin=60		Skin=80		Skin=100	
X	Y	X	Y	X	Y	X	Y	X	Y	X	Y
TIME (DAYS)	PV (USD)	TIME (DAYS)	PV (USD)	TIME (DAYS)	PV (USD)	TIME (DAYS)	PV (USD)	TIME (DAYS)	PV (USD)	TIME (DAYS)	PV (USD)
0.0		0.0		0.0		0.0		0.0		0.0	
0.0	10027.9	0.0	10027.9	0.0	10027.9	0.0	7888.7	0.0	6484.7	0.0	5615.7
0.0	15041.8	0.0	15041.8	0.0	15041.8	0.0	11832.9	0.0	9760.5	0.0	8423.5
0.1	22596.0	0.1	22596.0	0.1	22596.0	0.1	17782.7	0.1	14573.8	0.0	12635.1
0.1	33826.6	0.1	33826.6	0.1	33826.6	0.1	26673.8	0.1	21927.4	0.1	18986.0
0.2	50739.0	0.2	50739.0	0.2	50739.0	0.2	39909.7	0.1	32823.8	0.1	28478.6
0.3	76139.6	0.3	76139.6	0.3	76139.6	0.3	59963.5	0.2	49335.1	0.2	42650.4
0.5	114237.7	0.5	114237.7	0.5	114237.7	0.4	89908.6	0.3	73933.6	0.3	64040.8
0.7	171311.7	0.7	171311.7	0.7	171311.7	0.6	134889.3	0.5	110828.8	0.4	95990.8
1.1	256908.3	1.1	256908.3	1.1	256908.3	0.9	202317.9	0.7	166366.0	0.6	143978.1
1.7	385371.3	1.7	385371.3	1.7	385371.3	1.3	303407.5	1.1	249424.5	1.0	216015.8
2.6	577826.2	2.6	577826.2	2.6	577826.2	2.0	455030.3	1.7	374148.8	1.4	323982.7
3.9	866545.8	3.9	866545.8	3.9	866545.8	3.1	682363.3	2.5	561000.0	2.2	485814.9
5.8	1299124.9	5.8	1299124.9	5.8	1299124.9	4.6	1023102.2	3.8	841323.4	3.3	728615.0
8.7	1947202.5	8.7	1947202.5	8.7	1947202.5	6.9	1533799.3	5.7	1261395.9	4.9	1092389.0
13.1	2917432.6	13.1	2917432.6	13.1	2917432.6	10.3	2298562.0	8.5	1890560.6	7.4	1637500.4
19.7	4368682.7	19.7	4368682.7	19.7	4368682.7	15.5	3443290.2	12.7	2832827.7	11.0	2453923.9

(a) Discounted value per time step. This is done by merging oil and gas values (calculated previously) into a total value and applying a discount factor on it (10 % in this case).

Total Skin Discounted Value	
0	9.62E+08
20	9.63E+08
40	9.62E+08
60	9.63E+08
80	9.63E+08
100	9.61E+08

(b) Total Discounted Value for the different cases simulated.

Fig. 4.4: Excel tables reproducing what is performed in "Discounted Value Calculations" composite in Pipe-It project.

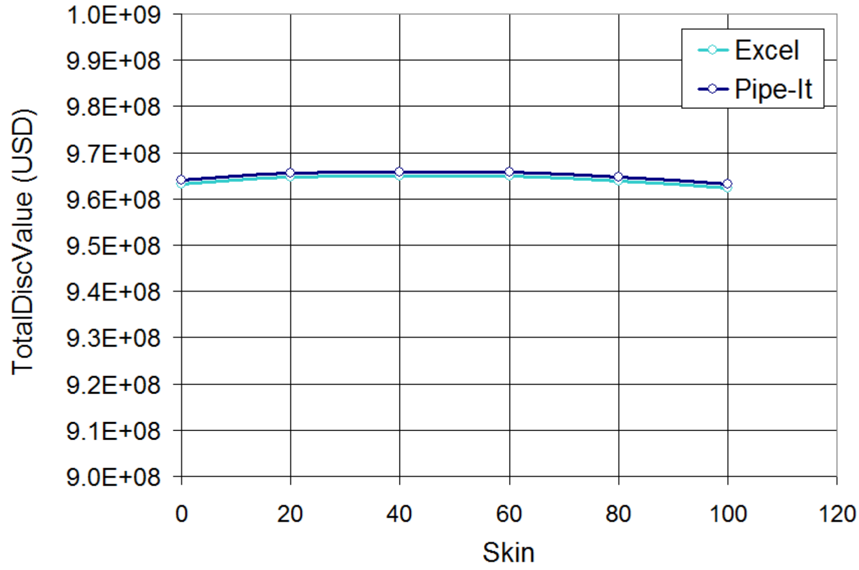
But as explained previously, the ultimate goal of these calculations is to compare them with results given by Pipe-It. A comparison of these results is given is Table 4.3.

Table 4.3: COMPARISON OF TOTAL DISCOUNTED VALUE CALCULATIONS

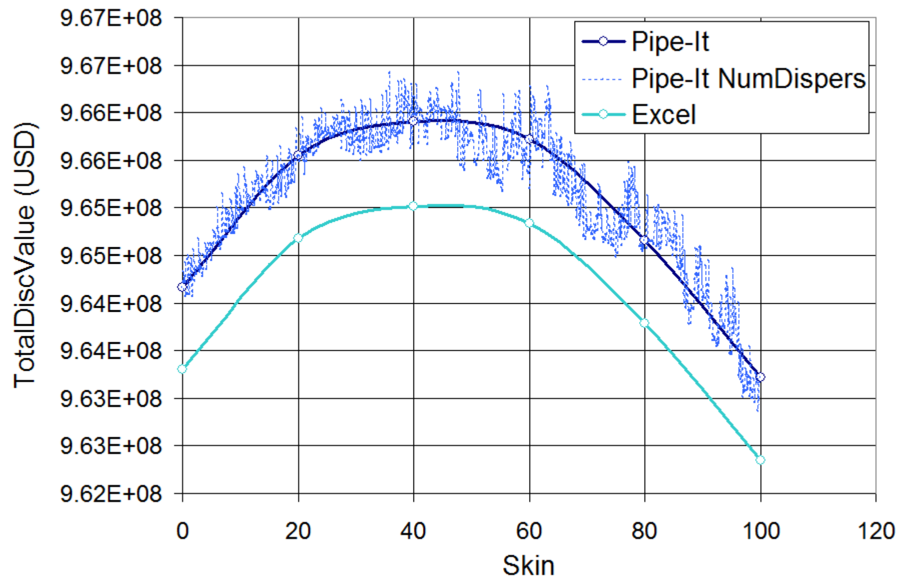
Skin	NPV Excel (x10^8 USD)	NPV Pipe It (x10^8 USD)	Error
0	9.63	9.64	**0.09%**
20	9.65	9.66	**0.09%**
40	9.65	9.66	**0.09%**
60	9.65	9.66	**0.09%**
80	9.64	9.65	**0.09%**
100	9.62	9.63	**0.09%**

We mention that total discounted value is referred to as NPV here for practical reasons. We can see that for all cases simulated, the error between manual calculations and Pipe-It calculations is around 0.1 %. Considering the purpose of this study and ranges of uncertainties in different part of a project, this error magnitude is acceptable. We can additionally plot total discounted value versus skin for both methods (Fig. 4.5).

What is interesting to notice is that numerical dispersion, revealed on Fig. 4.5(b) has almost the same amplitude as the error between two ways of calculation tested. This confirms, if needed, that error committed in Pipe-It calculations will not have adverse consequences on our conclusions.



(a) Total Discounted Value versus skin for Pipe-It and Excel manual calculations.



(b) Total Discounted Value versus skin revealing numerical dispersion due to SENSOR implicit calculations.

Fig. 4.5: Plots showing Total Discounted Value versus skin using both Pipe-It and manual calculations in Excel. Numerical dispersion (revealed using enlargement and a smaller step for skin) appears to be of same order of magnitude as error between Pipe-it calculations and Excel calculations.

4.2 Simulation Strategy Description

In this section, we will discuss step by step the protocol we used to carry out this investigation on ICDs. We will give more details on what we meant by "reservoir mapping" in previous chapter.

Principle

The point of view we adopted, to find out if using ICDs in gas condensate reservoirs has any advantage, is to simulate many reservoirs, with different properties. For each reservoir, an optimization is run, corresponding to Slave project described in section [Pipe-It project] of previous chapter. Of course, as required for every study, a scope must be defined. We decided to use a limited number of reservoir parameters as variables; these parameters are described in Table 4.4.

Table 4.4: VARIABLES DEFINITION

MASTER PROJECT		
Initial reservoir pressure	*Layer 1*	Pr_1
	Layer 2	Pr_2
Dew point pressure	*Layer 1*	Pdp_1
	Layer 2	Pdp_2
Thickness	*Layer 1*	H_1
	Layer 2	H_2
Reference depth for initialization	*Layer 1*	Z_{init_1}
	Layer 2	Z_{init_2}
Horizontal permeability	*Layer 1*	K_1
	Layer 2	K_2
SLAVE PROJECT		
Skin factor		S
Initial oil price		$OilPrice_{init}$
Initial gas price		$GasPrice_{init}$
Discount factor		DCF
Total discounted value		TotalDiscValue

We make them vary inside a limited range as shown in Eq. 4.2.

$$\text{Variables magnitude} = \begin{cases} 1000 \text{ psia} \leq \mathrm{P_r} \leq 11000 \text{ psia} \\ 1000 \text{ psia} \leq \mathrm{P_{dp}} \leq 11000 \text{ psia} \\ 10 \text{ m} \leq \mathrm{H_1} \leq 1000 \text{ m} \\ \mathrm{H_2} = 1000 \text{ m} \\ 10 \text{ mD} \leq \mathrm{K_1} \leq 1000 \text{ mD} \\ \mathrm{K_2} = 10 \text{ mD} \end{cases} \tag{4.2}$$

The main factor which dictated range of variation of parameters is range covered in PVT include file (Appendix C). Starting from this set of variables we derived some auxiliary variables (Eq. 4.5).

Table 4.5: AUXILIARY VARIABLES DEFINITION

Undersaturation degree	UndersatDeg	$\frac{P_r}{P_{dp}}$
Pressure contrast	PresContr	$\frac{Pr_1}{Pr_2}$
Thickness contrast	ThickContr	$\frac{H_1}{H_2}$
Permeability contrast	PermContr	$\frac{K_1}{K_2}$

From this starting point, we established all possible combinations with these variables using Excel (Eq. 4.3). The outcome is a matrix with more than 200 000 cases (more precisely: 11^4 x 5 x 3= 219 615 cases).

$$\text{Variables combinations} = \begin{cases} Pr = 1000, 2000, \ldots, 11000 \text{ psia} \\ Pdp = 1000, 2000, \ldots, 11000 \text{ psia} \\ H_1 = 10, 50, 100, 500, 1000 \text{ m} \\ K_1 = 100, 500, 1000 \text{ mD} \end{cases} \tag{4.3}$$

But this is from a purely mathematical point of view. Thus, we introduced some physics in this matrix definition. First, we want all reservoirs to be undersaturated. Then, initial dew point pressure in both layers must be greater than 3000 *psia*. These values are based on experience*. Most of condensate reservoirs lie inside these pressure ranges. These constraints are summarized in Eq. 4.4.

$$\text{Variables combinations under constraints} = \begin{cases} \mathrm{P_{dp}} > 3000 \text{ psia} \\ \frac{\mathrm{P_r}}{\mathrm{P_{dp}}} > 1 \end{cases} \tag{4.4}$$

This reduces significantly the number of cases to simulate with only 19 440 cases left. However it still represents a large number of computations and therefore some time should be spent on the most efficient way to speed up runs.

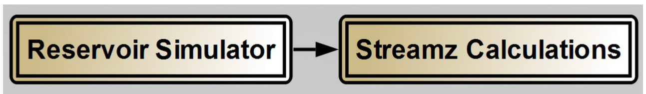
CPU Optimum Research

One should keep in mind that several thousands of cases are simulated in this study. On each case, an optimization is performed meaning that this case is run several times (this number depends on convergence rate). Therefore, any change that makes a single run faster can save a huge amount of time at the end of the day. We tried several ways to reduce run time of cases.

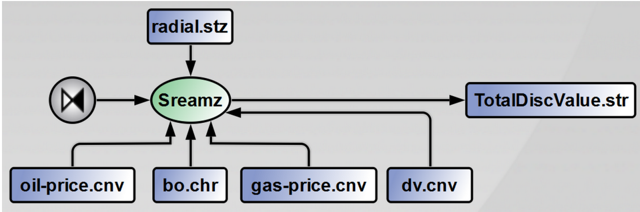
The first one is related to Pipe-It project architecture. As presented in Section 3.2 and developed in details in Appendix E, we divided our project in several blocks. Main reason for that is because we actually created Pipe-It project that way, step by step, following a sequential progression in complexity. Another reason is that it makes project easier to understand for a newcomer (more user friendly). But a major downside of this approach is related to time taken to open/close files, read them and write to them. These actions are executed for each block before going to next one.

One way to go around this problem is to combine as much blocks as possible in one single block (Fig. 4.6).

*These values are the result of discussions with Curtis H. Whitson who has more than 20 years experience in studying gas condensate reservoirs.



(a) First level Structure of Slave project. For a better efficiency, Products Separation and Economic Calculations composites were merged compared to initial Slave project.



(b) Organization of Streamz Calculations composite. All Streamz executions are brought together inside one process called *Streamz*.

Fig. 4.6: Improved structure of Pipe-It Slave project.

Of course Fig. 4.6(b) does not show anymore project structure and progression. But the main point is that *Streamz* process is launched only once with this new architecture, saving some computation time.

Another obvious way to reduce total run time is to execute the project on a more powerful computer. Several tests were made on different computers: a "Tablet PC"(personal computer), virtual machines owned by PERA (SENSOR2 and SENSOR3) and another virtual machine owned by cybernetics department in NTNU (kybpc2010). As expected, the more powerful the computer, the faster calculations.

Last way experimented to speed up simulation process is to launch several simulations in parallel. The point is to get the most out of processors embedded in computers. Results are exposed on Fig. 4.7.

We can draw several conclusions from this plot. First, main factor determining efficiency of running cases simultaneously is number of processors. We can see that for tests performed with SENSOR3 configured with 1 CPU only, running several cases at the same time is not really profitable. However for computers with more than 1 CPU, this technique appears to be powerful. For computers with 2 CPUs (most of current commercial computers), the optimum is located around 3 cases launched at the same time. For kybpc2010 it is a bit different; this virtual machine includes 8 CPUs. That is why calculations are faster and optimum is located around 6 cases launched simultaneously. Once running time for each case is reduced, whole set of simulation cases can be run. Results are discussed in the following sections.

4.3 Optimization Results

After having performed all the preparatory work discussed previously, we ran our matrix of around 19 000 cases. Results are detailed below.

Before filtering

Pipe-It results are extracted using procedure explained in Section 3.3. We present in Table 4.6 only *Best Cases*. Our criterion to select *Best Cases* is the revenue increase with a skin factor compared to

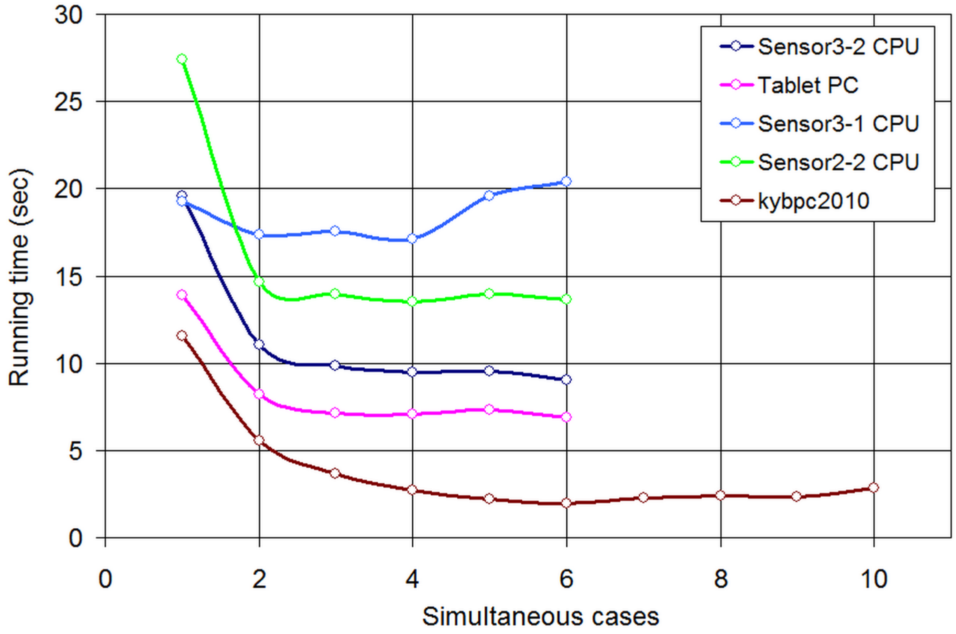


Fig. 4.7: Running time versus number of cases executed simultaneously for different computers. This plot shows that for computers comprising more than one CPU, running a single case at a time is not the most efficient strategy.

without skin factor†.

Table 4.6: BEST CASES RESULTS (before filtering)

Pr1	**Pdp1**	**Pr2**	**Pdp2**	**K1**	**K2**	**Perm Contrast**	**Skin MAX**	**NPV Skin MAX(x 10^8)**	**NPV Skin 0 (x 10^8)**	**NPV Diff**
9000	6000	4000	3000	400	5	80	73	7.00	6.75	**3.67%**
9000	6000	4000	3000	500	5	100	73	6.98	6.74	**3.54%**
9000	7000	4000	3000	500	5	100	73	7.05	6.81	**3.37%**
9000	6000	4000	3000	300	5	60	53	6.99	6.76	**3.24%**
9000	6000	4000	2000	400	5	80	73	7.32	7.09	**3.23%**
9000	6000	4000	2000	500	5	100	73	7.31	7.08	**3.14%**
9000	7000	4000	3000	400	5	80	53	7.05	6.83	**3.12%**
9000	6000	4000	2000	300	5	60	53	7.32	7.09	**3.03%**
8000	6000	4000	3000	500	5	100	83	6.77	6.57	**2.93%**

We can see that best results do not exceed 4% of increase in NPV. This means that the best we can expect using ICD (represented by a skin factor in our study) in our simulated reservoirs is an increase of 4% at best. We must add that most cases simulated do not show any increase in NPV when using ICD.

After filtering

Going further in results analysis, some simulated results are more "relevant" than others. By relevant we mean more representative of reality, of a potential actual gas condensate field. That is why we decided to introduce a new constraint. This last constraint is to fix initial reservoir pressure in low

†Total Discounted Revenue is referred to as "NPV" here for practical reasons.

permeability layer (*Layer 2*) greater than initial reservoir pressure in high permeability layer (*Layer 1*); in other words, we consider only cases where pressure contrast is lower than 1 (PresContr < 1) . We could imagine a peculiar reservoir where initially the opposite situation occurs ($\frac{Pr_1}{Pr_2} > 1$) but after depletion we would eventually reach a point where $\frac{Pr_1}{Pr_2}$ is lower than 1. The reason for this last constraint is that we are not interested in "exotic" reservoirs. We would like our synthetic data to be as close as possible to conventional field data. We present in Table 4.7 only *Best Cases*.

Table 4.7: BEST CASES RESULTS (after filtering)

Pr1	**Pdp1**	**Pr2**	**Pdp2**	**Press Contrast**	**H1**	**H2**	**Kx1**	**Kx2**	**Perm Contrast**	**Skin**	**NPV Skin MAX (x 10^9)**	**NPV Skin 0 (x 10^9)**	**NPV Diff**
8000	7000	10000	9000	**0.800**	50	100	500	10	50	90	1.16	1.15	**1.08%**
9000	7000	10000	9000	**0.900**	50	100	500	10	50	90	1.19	1.18	**1.03%**
9000	8000	10000	9000	**0.900**	50	100	500	10	50	90	1.19	1.17	**1.01%**
9000	6000	10000	9000	**0.900**	50	100	500	10	50	90	1.19	1.18	**0.98%**
8000	7000	9000	8000	**0.889**	50	100	500	10	50	90	1.15	1.14	**0.95%**
9000	8000	10000	8000	**0.900**	50	100	500	10	50	90	1.22	1.21	**0.94%**
8000	6000	9000	8000	**0.889**	50	100	500	10	50	90	1.15	1.14	**0.92%**
8000	7000	9000	6000	**0.889**	50	100	500	10	50	90	1.19	1.18	**0.90%**
8000	7000	9000	7000	**0.889**	50	100	500	10	50	90	1.18	1.16	**0.89%**

We can see that best results do not exceed 1% of increase in NPV with a skin factor compared to without skin factor. This means that the best we can expect using ICD is an increase of 1% at best. This shows that last constraint introduced has adverse effect on results. ICD potential benefits are almost divided by a factor four. Again, we must add that most cases simulated do not show any increase in NPV when using ICD.

4.4 Sensitivities on Best Results

In this section, we are making some sensitivity runs on *Best Cases* presented previously. The goal is to find new cases configurations giving better results regarding ICD potential. We decided to focus only on two parameters: permeability and layer thickness.

4.4.1 Permeability Values

As described previously in Simulation Strategy Description section (Section 4.2), permeability ratio $\frac{K_1}{K_2}$ varies in our simulations but the permeability of layer 2 (low permeability layer) is constant. The idea here is to select some cases, those with the best potential for ICDs, to maintain the permeability ratio constant but to change both layers' permeability.

Before filtering

Only few cases are selected for these sensitivity runs. They are presented in Table 4.8.

Results of these runs are presented on Fig. 4.8. They are expressed in terms of Total Discounted Value increase versus layer 2 permeability (K_2). For each run, the permeability ratio $\frac{K_1}{K_2}$ remains constant.

We notice that intrinsic permeability value plays a key role. All other parameters being constant, we observe for every run (1 to 8) high variations in terms of Net Present Revenue increase depending on K_2 value. We can see that the shape of Net Present Revenue increase versus K_2 curve is more or less independent on the permeability ratio considered. All curves present the same "bell-shape" with the peak located at the same place for all runs (K_2= 10 mD).

Table 4.8: CASES USED FOR PERMEABILITY SENSITIVITY (Before Filtering)

Run Number	**Pr1**	**Pdp1**	**Pr2**	**Pdp2**	**H1**	**Zinit1**	**H2**	**Zinit2**	**Perm Contrast**
1	9000	5000	4000	2000	50	10025	50	10075	40
2	8000	5000	4000	2000	50	10025	50	10075	40
3	9000	6000	4000	3000	50	10025	50	10075	60
4	7000	6000	4000	3000	50	10025	50	10075	60
5	10000	10000	5000	4000	50	10025	50	10075	80
6	9000	6000	4000	3000	50	10025	50	10075	80
7	7000	1000	4000	1000	50	10025	50	10075	100
8	10000	1000	4000	1000	50	10025	50	10075	100

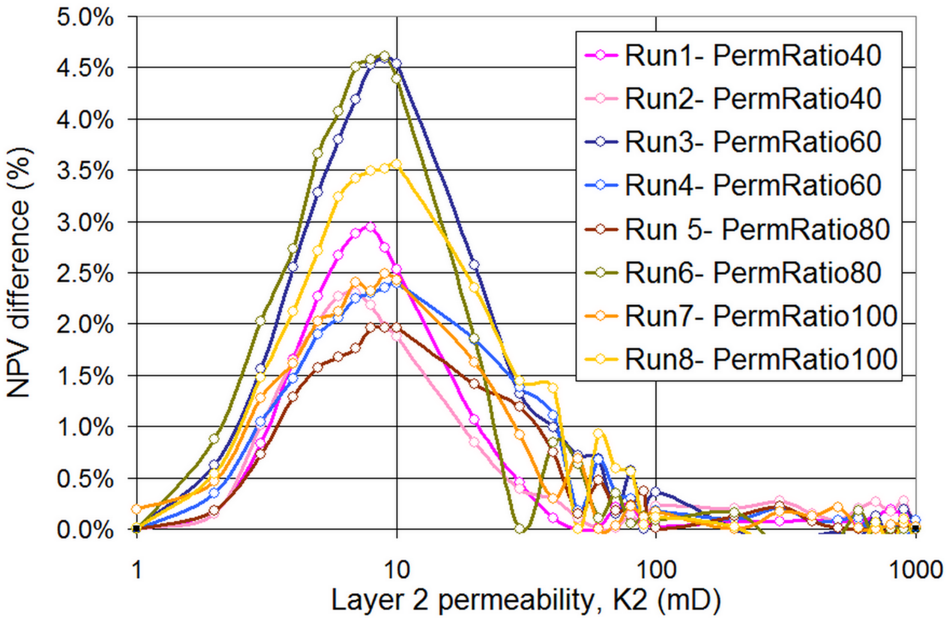


Fig. 4.8: Total Discounted Value increase versus *Layer 2* permeability. This plot is obtained using height different reservoirs (height Master cases). *Layer 2* permeability vary between 1 mD and 1000 mD (on a log scale) while permeability ratio $\frac{K_1}{K_2}$ is maintained constant and equal to 40. Results show that not only permeability ratio counts but values of permeabilities have also a significant importance.

After filtering

Here also, only few cases are selected. They are presented in Table 4.8. All cases take into account last constraint introduced in Case Matrix definition: $\frac{Pr_1}{Pr_2} < 1$.

Table 4.9: CASES USED FOR PERMEABILITY SENSITIVITY (After Filtering)

Run Number	Pr1	Pdp1	Pr2	Pdp2	H1	Zinit1	H2	Zinit2	Perm Contrast
1	8000	8000	10000	7000	1000	10500	100	11050	10
2	8000	3000	10000	9000	1000	10500	100	11050	10
3	8000	3000	10000	8000	1000	10500	100	11050	10
4	8000	7000	9000	6000	50	10025	100	10100	50
5	8000	7000	9000	7000	50	10025	100	10100	50
6	9000	7000	10000	8000	50	10025	100	10100	50
7	9000	7000	10000	9000	10	10005	100	10060	100
8	8000	6000	10000	9000	10	10005	100	10060	100
9	9000	7000	10000	9000	50	10025	100	10100	100

Results of these runs are presented on Fig. 4.9. They are expressed in terms of Total Discounted Value increase versus layer 2 permeability (K_2). For each run, the permeability ratio $\frac{K_1}{K_2}$ remains constant.

Conclusion is the same regarding the role played by intrinsic permeability value K_2. However, we can see that the shape of Net Present Revenue increase versus K_2 curve is now dependent on the permeability ratio considered. This new feature appears because we simulate here cases with a lower permeability ratio. It seems there is a "frontier". For cases with $\frac{K_1}{K_2} \geq 50$, the shapes of the curves are similar ("Bell-shape") no matter the ratio value, with a peak located at the same place for all runs (K_2= 10 mD). But for cases with $\frac{K_1}{K_2}$=10, the shape is completely different.

4.4.2 Layer Thickness Values

As described previously in Simulation Strategy Description section (Section 4.2), thickness ratio $\frac{H_1}{H_2}$ varies in our simulations but thickness of layer 2 is constant. The idea is to select some cases, those with the best potential for ICDs, to maintain the thickness ratio constant but to change both layers' thickness.

Before filtering

Here again, only few cases are selected. They are presented in Table 4.10. All cases take into account last constraint introduced in Case Matrix definition: $\frac{Pr_1}{Pr_2} < 1$.

Results of these runs are presented on Fig. 4.10. They are expressed in terms of Total Discounted Value increase versus layer 2 thickness (H_2). For each run, the thickness ratio $\frac{H_1}{H_2}$ remains constant and equal to 1. All cases in *Case Matrix*, before filtering, were built with a given thickness. Layer 1 and 2 thicknesses remained constant. That is why we kept $\frac{H_1}{H_2}$ constant during our sensitivity runs.

Conclusions are in all points similar to those given for sensitivity runs performed on permeability. We observe the same "Bell-shape" curve. The peak is more spread though, located around 100 ft (from 80 ft to 200 ft).

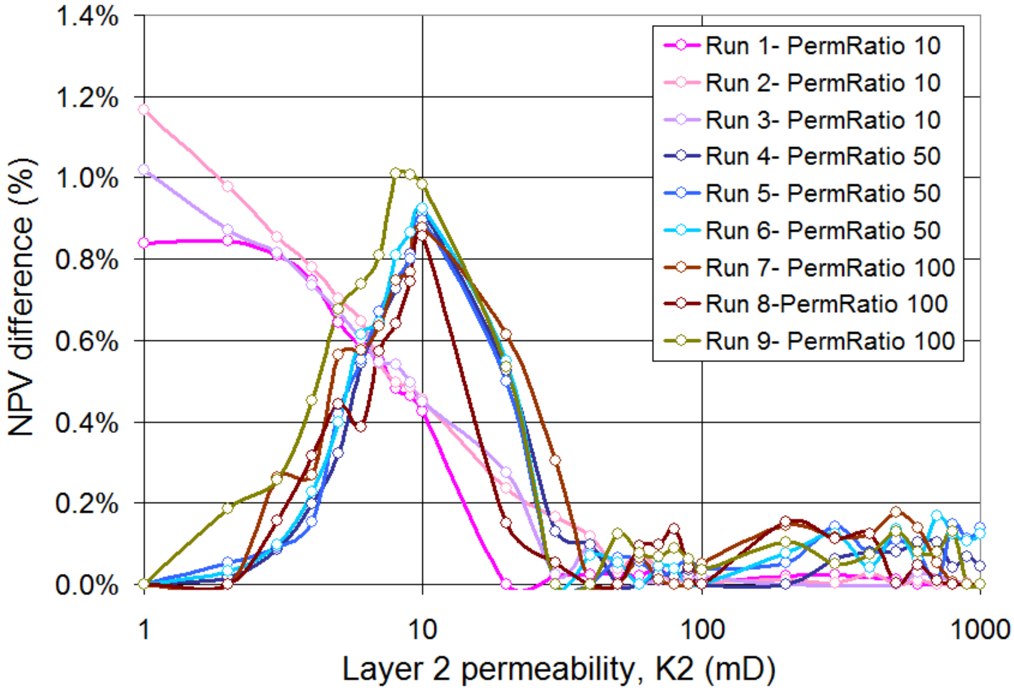


Fig. 4.9: Total Discounted Value increase versus *Layer 2* permeability. This plot is obtained using nine different reservoirs (nine Master cases after last filtering constraint introduction). *Layer 2* permeability varies between 1 mD and 1000 mD (on a log scale) while permeability ratio $\frac{K_1}{K_2}$ is maintained constant for each run. Results show that not only permeability ratio counts but values of permeabilities have also a significant importance.

Table 4.10: CASES USED FOR THICKNESS SENSITIVITY (Before Filtering)

Run Number	**Pr1**	**Pdp1**	**Pr2**	**Pdp2**	**Thickness Contrast**	**K1**	**K2**
1	9000	5000	4000	2000	1	400	10
2	8000	5000	4000	2000	1	400	10
3	9000	6000	4000	3000	1	600	10
4	7000	6000	4000	3000	1	600	10
5	10000	10000	5000	4000	1	800	10
6	9000	6000	4000	3000	1	800	10
7	7000	1000	4000	1000	1	1000	10
8	10000	1000	4000	1000	1	1000	10

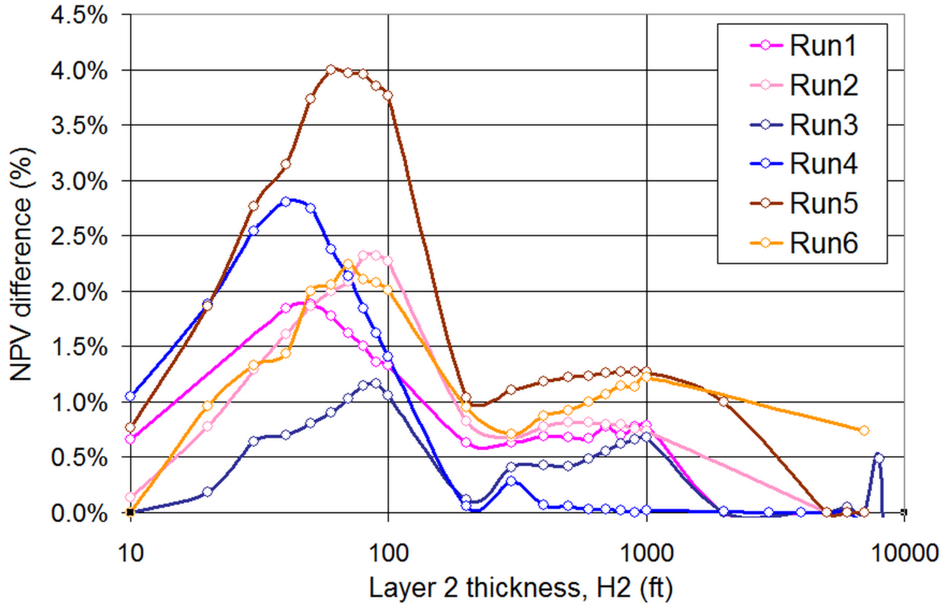


Fig. 4.10: Total Discounted Value increase versus *Layer 2* thickness. This plot is obtained using seven different reservoirs (seven Master cases after last filtering constraint introduction). *Layer 2* thickness varies between 10 ft and 10000 ft (on a log scale) while thickness ratio $\frac{H_1}{H_2}$ is maintained constant for each run. Results show that not only thickness ratio counts but values of layer thickness have also a significant importance.

After filtering

Here again, only few cases are selected. They are presented in Table 4.11. All cases take into account last constraint introduced in Case Matrix definition: $\frac{Pr_1}{Pr_2} < 1$.

Table 4.11: CASES USED FOR THICKNESS SENSITIVITY (After Filtering)

Run Number	**Pr1**	**Pdp1**	**Pr2**	**Pdp2**	**Thickness Contrast**	**K1**	**K2**
1	8000	7000	10000	9000	0.1	1000	10
2	8000	6000	10000	9000	0.1	1000	10
3	8000	7000	10000	9000	0.5	500	10
4	9000	7000	10000	9000	0.5	500	10
5	9000	3000	10000	7000	5	100	10
6	8000	3000	10000	6000	10	100	10
7	8000	3000	10000	7000	10	100	10

Results of these runs are presented on Fig. 4.11. They are expressed in terms of Total Discounted Value increase versus layer 2 thickness (H_2). For each run, the thickness ratio $\frac{H_1}{H_2}$ remains constant.

Conclusions are similar to those given for sensitivity using cases "Before Filtering". We observe the same "Bell-shape" curve. The peak is still located around 100 ft. It seems that unlike sensitivity runs on permeability, the shape of curves for sensitivity runs on thickness does not depend on thickness ratio value. All plots ("Before Filtering" and "After Filtering") show the behavior.

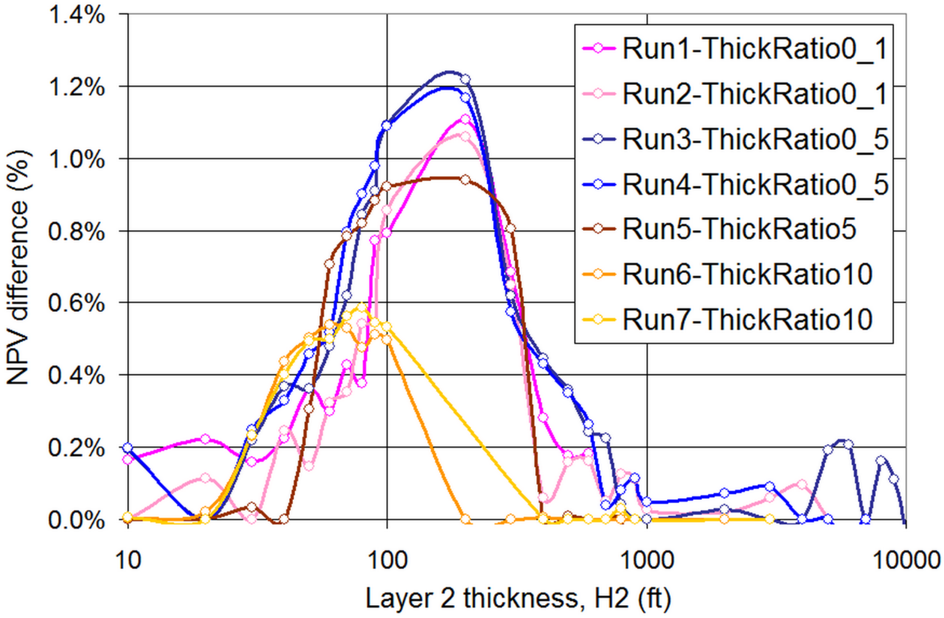


Fig. 4.11: Total Discounted Value increase versus *Layer 2* thickness. This plot is obtained using seven different reservoirs (seven Master cases after last filtering constraint introduction). *Layer 2* thickness varies between 10 ft and 10000 ft (on a log scale) while thickness ratio $\frac{H_1}{H_2}$ is maintained constant for each run. Results show that not only thickness ratio counts but values of layer thickness have also a significant importance.

4.5 Discussion

Many results were presented in this chapter. Some general trends emerge. First, both reservoir and Pipe-It models are reliable. Though consistency checks were performed only on a limited amount of cases (on one Master case, corresponding to six Slave cases), results are conclusive and allow us to be confident in our models.

Then, it is clear that our strategy was to run many cases (Master cases) in order to cover a large spectrum of reservoirs. This is to the detriment of reservoir model complexity (single-well model, Black-Oil characterization, simple PVT data, etc.). Despite this large amount cases executed, the framework of this thesis is limited and results may lack generality. All cases simulated have common characteristics and changing them could impact the results. PVT properties are the same, only one set of relative permeability curves is used, reservoir extension (r_e and r_w) and geometry (number of layers, no crossflow) remain the same. We could also imagine changing revenue calculations assumptions.

After initial run of "Case Matrix", we executed all cases with a different strategy: extending permeability range keeping layer thickness constant and extending layer thickness range keeping permeability constant. From these simulations emerged cases referred to as *Best Cases*. Sensitivity runs were made in an attempt to improve these *Best Cases*. These sensitivities focused on permeability and thickness parameters. We found out that not only ratios matter (permeability ratio and thickness ratio) but also intrinsic values of parameters (permeability and layer thickness) have some importance. This result is of major importance. Our strategy regarding permeability and thickness is to change only ratios ($\frac{K_1}{K_2}$ and $\frac{H_1}{H_2}$). Intrinsic value of K_2 and H_2 remain the same for instance. This means that cases where ICD appears to have no benefits could turn into cases where ICDs have benefits if intrinsic values were changed.

However, the current trend emerging from all our calculations is that none of reservoir configurations simulated showed significant upsides in using ICDs. This does not mean that ICDs are not suitable for gas condensate reservoirs with certainty. It just means that within the span covered by our investigations, the use of ICDs with gas condensate reservoirs is questionable. But, we will see in the next chapter that many directions were not explored and thus further investigations are necessary before being able to reach a conclusion.

Chapter 5

Possible perspectives

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5.1 ICD modelization

As explained earlier in this report, we have not modeled ICDs directly but we have used a surrogate: skin factor. For first order calculations, which is the objective of this study, this way around works fine. However, if one wants to go further and be more realistic (for a commercial study for instance), ICD modeling must be improved.

Rate-Dependent Skin

As mentioned in previous chapters, the pressure drop provided by a given ICD depends on flow rate going through this ICD. We can take the example of flow through nozzle-based ICDs which is governed by Bernoulli law ($\Delta \mathrm{P} \propto \mathrm{q}^2$). However, in our study, we decided to model ICDs with a constant skin factor (independent of flow rate). This is a severe approximation. For the purpose of our study, it seems to be a reasonable assumption. But if we wanted to go further in our investigations, we should find a more realistic model for ICDs. A good step in this direction would be to add a *rate dependent skin* to our initial skin factor. This rate dependent term, *Dq*, is related to Forchheimer non-Darcy flow model. Our new model of ICD would be a rate dependent skin term, $\mathrm{S_T} = \mathrm{S} + \mathrm{Dq}$, i.e. two parameters (S;D).

Match ICD configurations with Pressure Drops

Another improvement would be to match carefully ICD configurations with (S;D) couples. To do so, we should translate pressure drops through ICDs into (S;D) values using flow equations. For instance, for the flow through nozzle-based ICD, we should try to match Bernoulli equation.

For incompressible flow, Bernoulli equation is quite simple and, as mentioned above, pressure drop is proportional to the square of flow rate ($\Delta P \propto q^2$). But, in gas condensate reservoirs, main phase flowing is gas, meaning we probably have to consider compressibility effects. In this case, analytical approach might not be possible. A solution could be to perform flow tests on ICDs (gas flow and condensate flow), to derive flow charts (ΔP vs q), and thus to try to match a specific ICD configuration with a (S;D) couple. But, for these tests to be conclusive we must be close to reservoir conditions which is not easy to set up.

5.2 Sensitivity to other parameters

For many reasons (time, complexity, computational facilities, etc.), we kept the scope of this study quite limited. Our results are specific to the strategy we adopted and may lack generality. Many directions regarding ICDs in gas condensate reservoirs are not covered here and could be investigated.

PVT properties

Sensitivities on PVT properties are limited to changing dew point pressure (Pdp) in both layers independently. All data are taken from the same PVT table. We could imagine having different type of fluids, run simulations using different PVT tables and see the effect on results. We could even imagine using different PVT tables for *Layer 1* and *Layer 2*.

Relative Permeability Curves

In this study we only consider one single set of relative permeability curves. These curves are based on analytical expressions as explained in Section 3.1. It could be interesting to see how results are changed if we use different relative permeability curves. Indeed, relative permeability curves can be of major importance in gas condensate reservoirs, mainly due to "Condensate Blockage Effect"*.

Different Reservoir Model

We must remember that sensitivities operated on reservoir itself are very limited in our study; the only parameter modified is layer thickness. We could study the impact of changing reservoir extent (r_e), wellbore size (r_w), dividing the reservoir in more than two layers, considering a horizontal well instead of a vertical one, or even change completely our reservoir model and switch to a full-field model. We could also allow crossflow and vary the $\frac{K_v}{K_h}$ ratio. The influence of production strategy (represented by gas target rate) could be considered. We could imagine a reservoir including an aquifer support and investigate consequences of introducing water on our results. Many more factors could be examined.

Value Calculations Assumptions

Our objective function, total discounted value of the project, is based on assumptions regarding product prices, price escalation and discount factor. Considering the importance of product (oil and gas) and their high volatility, it seems relevant to run some sensitivities on these parameters. Price escalation (which counteracts discounting) and discount factor are of second order importance (lower volatility). Besides, costs of ICD could be included in our study. It would make calculations more realistic and especially upsides using ICDs, if any, would be balanced by extra costs induced by ICD implementation (Price of ICDs, extra wells, longer time for completion ...).

5.3 Use of other Solvers

For our calculations, we used only one type of solver: Nelder Mead Simplex Reflection solver. We made this choice since it is the default solver incorporated in Pipe-It. Nevertheless, other solvers could be used; several other solvers are embedded in Pipe-it: GRG (Generalized Reduced Gradient) Non

*There are many papers and articles dealing with this subject, but for further information on condensate blockage we suggest [Whitson 1999, Wheaton 2000].

Linear solver (standard Excel solver), Trivial solver, and IPOPT (Interior-Point OPTimizer) solver. Moreover, it is possible to add our own solver as a plug-in. Changing solvers should not change results significantly but it could change speed of convergence and consequently offer more opportunities to study other scenarios.

5.4 Reservoir vs Wellbore

An interesting new angle for this study would be to compare the reservoir-centered approach with the wellbore-centered approach. In our current reservoir model, the wellbore is not represented. We stop modelization at $r = r_w$. It would be interesting to study ICDs effect taking into account the wellbore ($r < r_w$). Some reservoir simulators (Eclipse, CMG, Nexus ...) allow wellbore modeling (for instance using *Multi Segment Well* model developed by Holmes [Holmes 1998]) and even sometimes ICD can be modeled directly. But what would be even more interesting is to perform the same study as presented in this report but using a near-wellbore simulator. Indeed, ICD being a completion device, it seems relevant to capture wellbore effects. Then we should investigate if conclusions are the same with both point of view (reservoir point of view and wellbore point of view).

Chapter 6

Conclusions and Recommendations

Modeling Inflow Control Devices in gas condensate reservoirs using reservoir simulation has been studied. An r-z radial grid single-well model was used. Revenue calculation optimization was performed on a large number of different reservoir synthetic data. Based on this work, major findings are presented as follows:

1. A large majority of cases simulated shows that using ICDs with condensate reservoirs presents no upside whatsoever in terms of revenues.

2. Revenue increase calculations reveal that none of the thousands synthetic condensate reservoirs simulated shows a significant revenue increase when using ICDs.

3. Revenue increase can be up to 4 % using ICDs for some cases referred as *Best Cases*. However, after introducing the constraint $\frac{Pr_1}{Pr_2} < 1$, meaning that initial pressure in high permeability layer (layer 1) is lower than initial pressure in low permeability layer (layer 2), not a single case shows a revenue increase greater than 1 % when using ICDs.

4. *Best Cases* obtained "before filtering" tend to have a high initial pressure in layer 1 ($\mathrm{Pr}_1 \geq 8000$ psia), a high pressure contrast $\left(\frac{Pr_1}{Pr_2} \geq 2\right)$, a moderate degree of undersaturation in both layers $\left(\frac{Pdp_1}{Pdp_2} \equiv 1.2 - 1.5\right)$ and a high permeability contrast $\left(\frac{K_1}{K_2} \geq 60\right)$ but not "too high" $\left(\frac{K_1}{K_2} \leq 1000\right)$.

5. Best Cases obtained "after filtering" tend to show pretty much the same characteristics. A high initial pressure in layer 1 ($\mathrm{Pr}_1 \geq 8000$ psia) associated of course to a high initial pressure in layer 2 $\frac{Pr_1}{Pr_2} < 1$, a low pressure contrast compared to before filtering though $\left(\frac{Pr_1}{Pr_2} \leq 1.2\right)$. We notice a moderate degree of undersaturation in both layers $\left(\frac{Pdp_1}{Pdp_2} \equiv 1.1 - 1.5\right)$ and a high permeability contrast $\left(\frac{K_1}{K_2} = 50 \text{ because only permeability ratios of 10, 50 and 100 were tested}\right)$.

6. Sensitivity runs performed show that not only ratios matter (permeability ratio and thickness ratio) but also intrinsic values of parameters (permeability and layer thickness) have some importance. Values likely to give the best results are: $\mathrm{H}_2 \equiv 100$ ft independently of $\frac{H_1}{H_2}$, $\mathrm{K}_2 \equiv 1$ mD for $\frac{K_1}{K_2} \leq 10$ and $\mathrm{K}_2 \equiv 1$ mD for $\frac{K_1}{K_2} \geq 50$.

7. This research on potentials of using ICDs in gas condensate reservoirs is without prior studies in the literature. This study is just a first step in this pioneering area and many aspects are overlooked. Therefore the conclusions presented here are strictly limited to the framework of this study and might lack of generality.

Appendix A

Description of utilized softwares

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A.1 SENSOR6k

SENSOR stands for *System for Efficient Simulation of Oil Recovery* and is a reservoir simulator. It is a trademark from Coats Engineering Inc. founded by Dr. Keith H. Coats. SENSOR handles 3D Black-Oil and Compositional fluid characterizations; it can model single porosity, dual porosity, dual permeability reservoirs. Both Impes and Implicit formulations are included. Three linear solvers are available: Bandwidth direct (D4), Orthomin with Nested Factorization, and Orthomin with ILU (red-black and residual constraint options) [CoatsEngineering 2009]. The gridding is highly flexible as it can handle any grid type or combination of grid type. SENSOR can be launched from a command prompt and therefore being executed within other applications. This functionality is used in our study since SENSOR is run from Pipe-It both in Master and Slave project. But, the main competitive advantage of SENSOR, compared to other reservoir simulators, is efficiency. In terms of CPU time needed for a simulation run, SENSOR is very efficient. Typically, SENSOR speed is 3 to 10 times higher than the one from other competitors [CoatsEngineering 2010c]. This is supported by several extensive industry benchmarks [CoatsEngineering 2010a].

SENSOR6k is a restricted version of SENSOR. Problems containing a maximum number of 6000 grid blocks can be simulated. This version is proposed to students and to non-profit organizations [CoatsEngineering 2010b].

I am highly satisfied with the choice of SENSOR as reservoir simulator for my thesis. SENSOR is definitely a user friendly reservoir simulator. But, the most important feature is its speed and consistent reliability (robustness). It was critical for this project as part of it was dedicated to some kind of "reservoir mapping" consisting in launching several thousands simulation cases. Without SENSOR efficiency, it would have not been possible to perform this study that way, at least within this timeframe.

A.2 Pipe-It 1.0

Petrostreamz Pipe-It (called Pipe-It in the following) is a software developed by *Petrostreamz AS*, an affiliate of *PERA AS* founded by Curtis H. Whitson. Pipe-It provides a generic framework to connect workflows together. The main idea behind it, is to represent a workflow the same way it exists in reality within a Pipe-It project. Pipe-It aims at facilitating asset optimization and exploitation in the petroleum sector. Visualization is made possible thanks to an insightful GUI (Graphical User Interface) which allows projects to be organized in a multi-level architecture. This is to enable users to decide which level of complexity must be displayed according to the objective of the project and/or the point of view adopted. The fact that the entire project or only elements of a project can be run separately is a great capability of Pipe-It. It helps in giving the possibility to build a project step by step and to keep track on the integrity of each element of the project [PetroStreamz 2010b].

Main elements composing a Pipe-it project are *Resources*, *Connectors*, *Processes*, and *Composites*.

Fig. A.1: Pipe-It project main elements [PetroStreamz 2010a].

Resources are mainly input and output files; but it can be any file stored on the disk that contains information related to a quantity. A Process is any operation performed on a Resource which results in the production of another Resource. Processes can be represented by any third party software as long as it is executable from a command line (SENSOR, ECLIPSE, Excel etc.). Connectors link Resources to Processes and vice versa as shown in Fig. A.1.

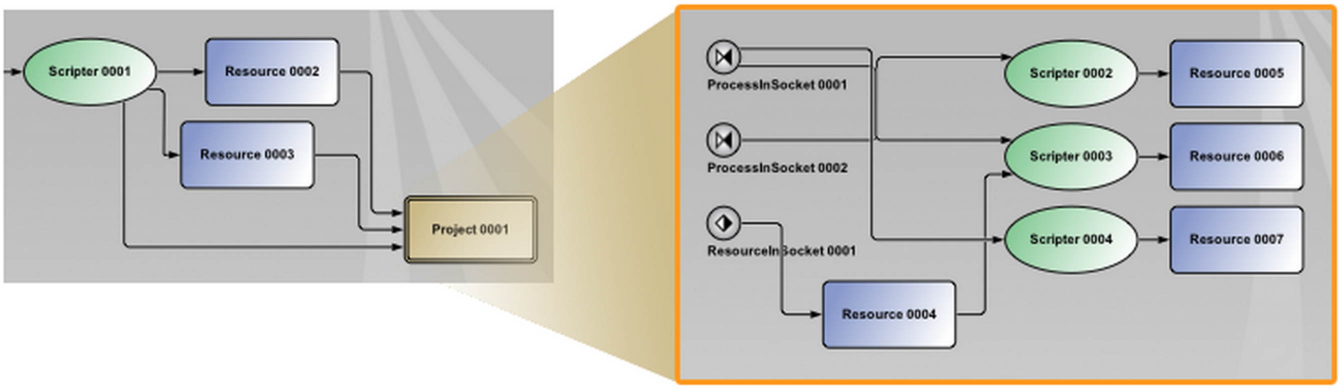
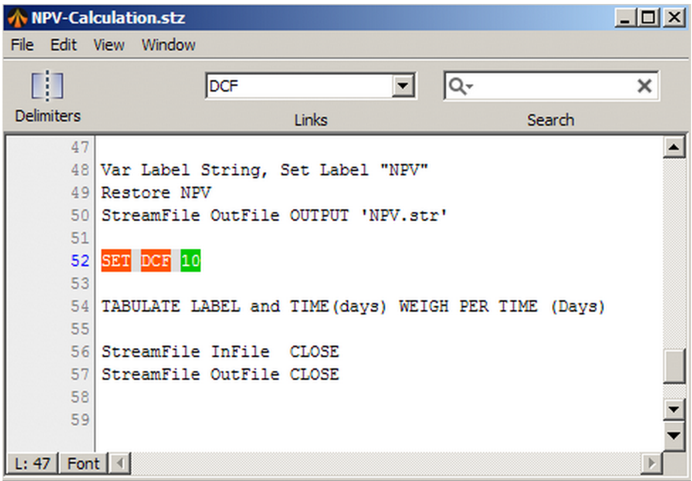


Fig. A.2: Description of Pipe-It *Composite* structure. Snapshots show that a composite is a "sub-project" which can contain many [PetroStreamz 2010a].

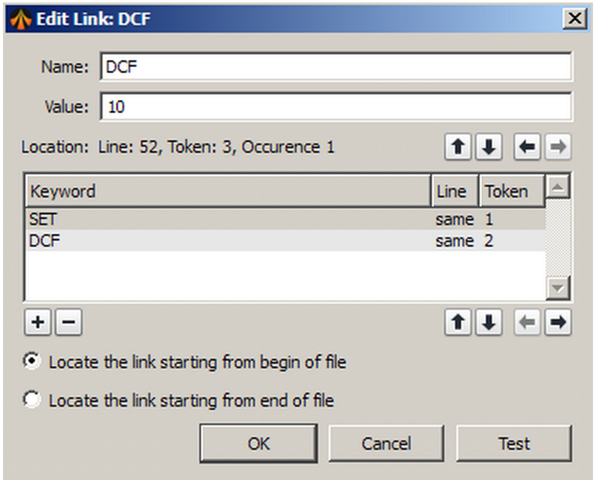
To make Pipe-It project structure clearer, Composites are used. A Composite groups several Resources and Processes (and other Composites) into a single visual element as shown in Fig. A.2. Connections from elements inside a Composite to elements outside are ensured using Sockets. Composites can be seen as "Sub-Projects" [PetroStreamz 2010b].

A.2.1 Linkz

Linkz is a built-in feature of Pipe-It. It allows users to locate values of variables inside a Resource(typically a text file such as input or output simulation files). To achieve this goal, *Linkz* utilities are available. Fig. A.3(a) shows *Linkz* file viewer . *Linkz* values are highlighted in green to show where Linkz search is pointing. To locate this value inside the text file, *Linkz* needs some surrounding "anchor" tokens (keywords) to be added. The link is defined relatively to surrounding tokens. By double clicking on the link (highlighted in green) you can modify link definition through an Edit Link Dialog window (Fig. A.3(b)).



(a) *Linkz* file viewer. In green, value location where the link is pointing.In red, surrounding keywords to locate the value.



(b) *Linkz* dialog window summarizing link definition and allowing adjustments.

Fig. A.3: *Linkz* utility description [PetroStreamz 2010a].

Link name can be edited and modified. the current value of the variable is displayed. The location of the link (line number and token index in the line) as well as the number of occurrences of the link are given. With the arrow buttons users can modify keywords positions while plus and minus buttons allow to add or remove a keyword.

A.2.2 Pipe-It Optimizer

Pipe-It Optimizer is a feature included in Pipe-It to allow users to perform optimization related to a given Pipe-It project (Fig. A.4) or sub-project (Composite). The principle is to define some input variables, an objective function, and some constraints if needed. Then the optimizer modifies these variables, triggers a run of Pipe-It model, examine the results according to the objective function and constraints. Thus, depending on solver choice, variables are adjusted and procedure repeated until a feasible solution or a maximum or a minimum of the objective function is found. Variables are located in Resource files using *Linkz*. There are several types of variables in the optimizer [PetroStreamz 2010b]:

- VAR — user-or optimizer-specified, within a user-defined range, and updated before the project is executed. If a VAR is located in a file (using *Linkz*), the update phase will consist in writing to this file.

- AUX — set by equation, read from a resource file, or user-defined. They are updated after VARs but still before the model is run. If an AUX is located in a file, the value will be read from the file (and not written to the file as for a VAR) during the update phase.

- CON — normally a constraint set by equation, read from a resource file, or user-defined. They are updated after the model is run. If a CON is located in a file, the value will be read from the file during the update phase.

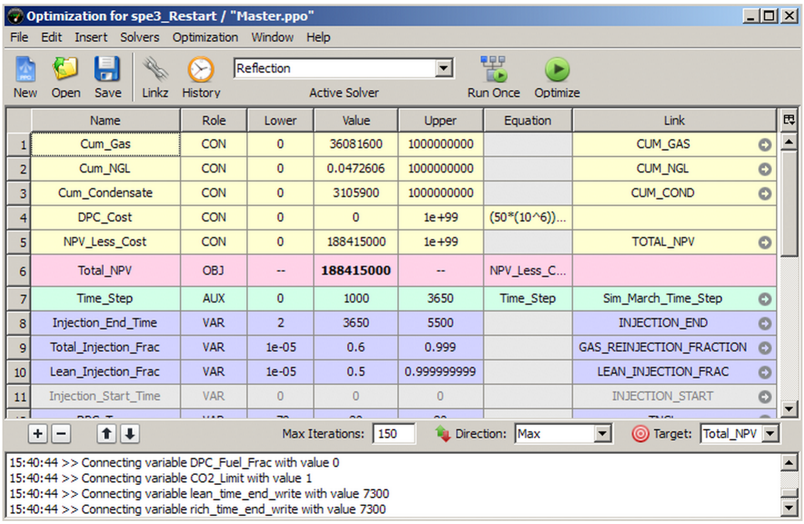


Fig. A.4: *Optimizer* GUI outline [PetroStreamz 2010a].

- OBJ — usually an objective or Key Performance Indicator (KPI) which is to be maximized or minimized. This type of variable is the last to be updated (after all the other variables have been checked against user-defined range).

Different solvers are embedded in Pipe-It such as Reflection solver, GRG (Generalized Reduced Gradient) Non Linear solver (standard Excel solver), Trivial solver, and IPOPT (Interior-Point OPTimizer) solver. The way variables are altered from one iteration to another depends on which solver is selected. Some tuning parameters are available; the most useful being "Maximum Number of Iterations" that gives the instruction to the optimizer to stop the run after a given number of iterations. Thus, Optimizer returns the best solution among these iterations (even if it is not a local/global maximum or minimum).

A.2.3 Pipe-Itc

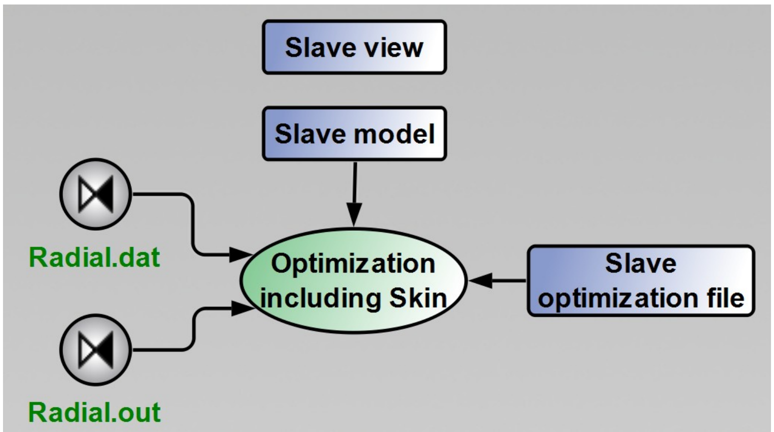
Pipe-Itc.exe is a non GUI version of Pipe-It. It can be called from other programs or by Pipe-It itself [PetroStreamz 2010b].

An example of possibilities offered by Pipe-ItC is presented on Fig. A.5. Fig. A.5(a) shows the inside of a Composite called "Link to Slave Project" located in the Master Pipe-It project. Process "Optimization including Skin" launches *Pipe-ItC* which runs Slave project model, "Slave.ppm", and performs an optimization using optimizer file "Slave.ppo". All these operations are behind-the-scene since no GUI is opened using Pipe-ItC.

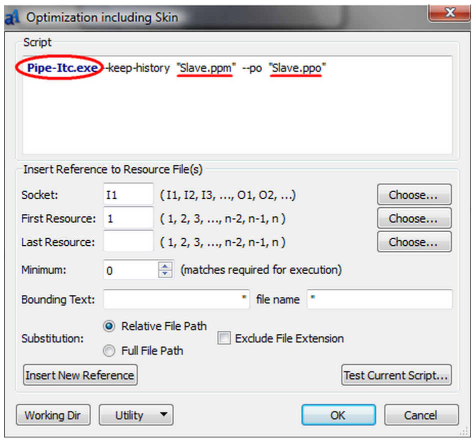
A.2.4 Case Matrix

In addition to optimization runs using a specific solver, Pipe-It Optimizer offers the possibility to run a predetermined set of cases using *Case Matrix* tool (Fig. A.6(a)).

The procedure is very similar to optimization procedure described previously, except that with Case Matrix there is no iterative process. Only a single run for each case. It is possible to run Case Matrix tool with or without defining an objective function while an objective function must be defined for optimization runs using a solver. The set of cases is entered in an Excel-like format spreadsheet (Fig. A.6(b)). Case Matrix is really useful for studies involving several datasets and different cases are to be run with no need for optimization.

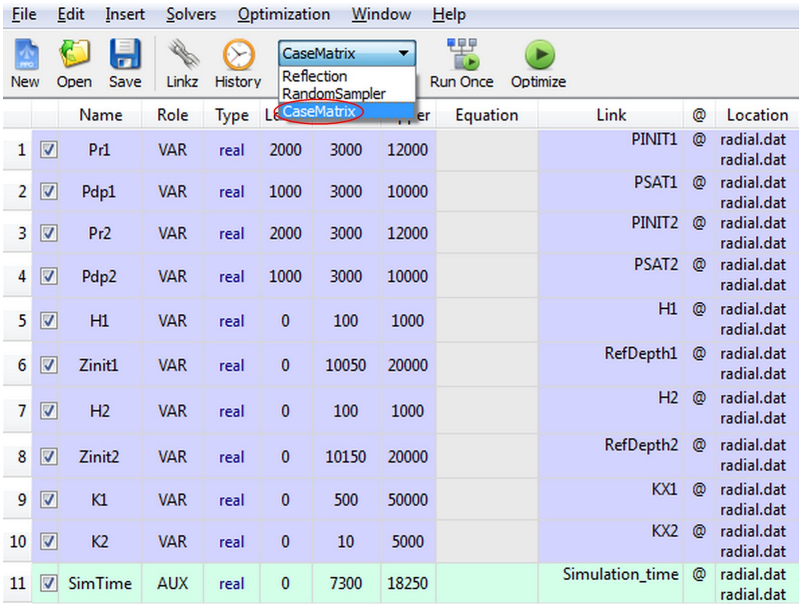


(a) Link to Slave project structure. The process "Optimization including Skin" executes Pipe-ItC to run Slave project and optimization.

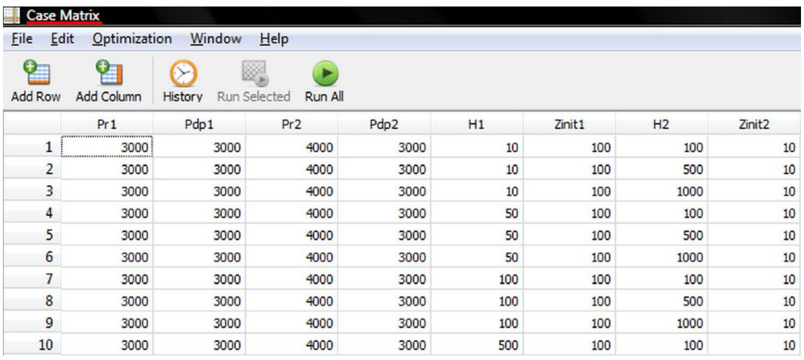


(b) Script associated to Optimization Including Skin process. Using PipeItC, it executes Slave project run and optimization.

Fig. A.5: Example of possible use of Pipe-ItC.



(a) View of solvers drop down list in *Optimizer* GUI.



(b) Outline of *Case Matrix* feature inside Optimizer module.

Fig. A.6: CaseMatrix

Appendix B

Reservoir Model: Dataset for Base Case

```
TITLE

Test Problem for ICD (Inflow Control Device) modeling of Gas Condensate wells
Radial Well r-z grid
Fevang Rich Gas PVT
KRANALYTICAL Fevang-like Rel Perm
Two non-communicating layers (LNX)

ENDTITLE

C INITIAL DATA

GRID  20 1 2        ! Nr  Ntheta  Nz
IMPLICIT            ! Radial r-z recommended
C D4                ! small pb recommended solver
RUN   ! Enable Sensor to override PVT errors

MISC  1.00000  2.67E-6  62.428  .50  5E-6  7000 ! Bw cw denw visw cr PREF

C Fevang Rich Gas PVT

INCLUDE
pvt.inc

C Check .out file vs Fevang KR tables.

KRANALYTICAL  1   ! Analytical Rel. Perm and Cap. Press : "1" means we are using "table 1"
0.25 0.25 0.10 0.00 ! Swc Sorw Sorg Sgc (Sgr)
0.20 0.74 1.00   ! krwro krgro krocw
3.00 3.00 3.00 3.00 ! nw now ng nog (nwg Swcg)

C -------------------------------------------------------------------------------------
C Regions: 1 = layer 1 , 2 = layer 2
C -------------------------------------------------------------------------------------
REGION CON      ! CON ~ Constant value
 1
MOD          ! MOD ~ Modify
 1 20 1 1 2 2 = 2 ! Region 2 is defined
```

```
RADIAL
 1                   ! Method 1: enter rw, rwe, and delta Theta
 0.35 3000.0         ! rw  re
 360.0               ! Ny * delta Theta values (in degrees)

THICKNESS CON    ! Layer 2 thickness
 100

MOD
 1 20 1 1 1 1 = 100    ! Layer 1 thickness

DEPTH CON ! Depth of top layer blocks
 10000

POROS CON ! Porosity
 0.30

KX CON ! Permeability in the x-direction
 10

MOD
 1 20 1 1 1 1 = 500 ! Different permeability for layer 1: Kx1=10*Kx2

KY EQUALS KX
KZ EQUALS KX

MOD
 1 20 1 1 1 2 = 0    ! LNX: Kz=0 -> No crossflow between layer 1 and 2

INITREG CON     ! Gridblock Initialization by region (initialization by equilibration)
 1
MOD
 1 20 1 1 2 2 = 2

INITIAL 1     ! Initialization
DEPTH  PSATDP       ! Initial dew point pressure (psia) at ref depth
 10050. 3000
PINIT 5000         ! Initial pressure at reference depth
ZINIT 10050.0       ! Reference depth

INITIAL 2
DEPTH PSATDP
 10150. 3000
PINIT 5000
ZINIT 10150.0

ENDINIT       ! End of Initial data section
```

```
PSM

C MODIFICATION DATA

! No modification data

C RECURRENT DATA

WELL
 I J K1 K2 SKIN RW    ! i, j and k indices of perf   Skin factor  Wellbore Radius
P1   ! Well name
 1 1 1 1  0 0.35
 1 1 2 2  0 0.35

WELLTYPE
 P1     2             !   well 1 is a Mscf/d producer

BHP     ! Limiting  BHP (psia)
 P1   1000

RATE
 P1    50000          ! Mscf/d target rate

MAPSPRINT 1  P SW SG SO
MAPSFREQ  1       ! Maps printout
WELLSUM   ! EoR well summaries
 P1 1

REGSUM
 1  1
 2  1
SUMFREQ 0 ! Freq of lines in End of Run summaries (0= every time step)
WELLFREQ 1 ! Well table printout (1= only at times entered in datafile)

DT 0.01 ! First time step specification

TIME 30 ! Report frequency in the output file
TIME 90
TIME 180
TIME 365
TIME 7300 365 ! TIME time dtime   where dtime (reports created at multiple of dtime until TIME)
END
```

Appendix C

PVT Tables Include File

```
C ==================================================================================
C Sensor Black-oil PVT table(s)
C ==================================================================================
C PVT Table   1
PVTBO    1
C         C1    C2    C3     C4 C5         C6        C7   C8 C9
C          P     P    RS     BO rs         BG        VIS CO DEN
UNITS      1.    0.   1000.  1. 1000.      0.001      1. 1. 1.

DENSITY  47.36049   0.05499        0.        0.

PRESSURES        39        39
    1000.0    1500.0    1750.0    2000.0    2250.0    2500.0    2750.0
    3000.0    3250.0    3500.0    3750.0    4000.0    4250.0    4500.0
    4750.0    5000.0    5250.0    5500.0    5899.3    7200.0    7400.0
    7600.0    7800.0    8000.0    8200.0    8400.0    8600.0    8800.0
    9000.0    9200.0    9400.0    9600.0    9800.0   10000.0   10200.0
   10400.0   10600.0   10800.0   11000.0

C    psia             Mscf/STB
     PSAT               RS

    1000.0            0.238308
    1500.0            0.387433
    1750.0            0.468613
    2000.0            0.554745
    2250.0            0.646137
    2500.0            0.743109
    2750.0            0.845962
    3000.0            0.954922
    3250.0            1.070056
    3500.0            1.191087
    3750.0            1.317213
    4000.0            1.446734
    4250.0            1.576817
    4500.0            1.703499
    4750.0            1.822363
    5000.0            1.929375
    5250.0            2.021598
```

```
    5500.0           2.096606
    5899.3           2.174363
    7200.0           2.477926
    7400.0           2.523668
    7600.0           2.569193
    7800.0           2.614511
    8000.0           2.659631
    8200.0           2.704561
    8400.0           2.749309
    8600.0           2.793882
    8800.0           2.838287
    9000.0           2.882532
    9200.0           2.926620
    9400.0           2.970559
    9600.0           3.014355
    9800.0           3.058011
   10000.0           3.101532
   10200.0           3.144924
   10400.0           3.188191
   10600.0           3.231337
   10800.0           3.274366
   11000.0           3.317281

C         psia          psia          RB/STB         cp
          PSAT           P              BO          VISO

         1000.0        1000.0       1.239570     0.378030
                       1500.0       1.224760     0.417580
                       1750.0       1.218130     0.437300
                       2000.0       1.211940     0.457000
                       2250.0       1.206130     0.476650
                       2500.0       1.200680     0.496280
                       2750.0       1.195530     0.515860
                       3000.0       1.190670     0.535410
                       3250.0       1.186060     0.554910
                       3500.0       1.181690     0.574370
                       3750.0       1.177530     0.593770
                       4000.0       1.173570     0.613130
                       4250.0       1.169800     0.632430
                       4500.0       1.166180     0.651680
                       4750.0       1.162730     0.670860
                       5000.0       1.159420     0.689990
                       5250.0       1.156240     0.709050
                       5500.0       1.153190     0.728040
                       5899.3       1.148554     0.758743
                       7200.0       1.135220     0.855310
                       7400.0       1.133369     0.870633
```

	7600.0	1.131566	0.885399
	7800.0	1.129809	0.900105
	8000.0	1.128097	0.914751
	8200.0	1.126427	0.929335
	8400.0	1.124798	0.943858
	8600.0	1.123208	0.958319
	8800.0	1.121656	0.972717
	9000.0	1.120140	0.987051
	9200.0	1.118659	1.001322
	9400.0	1.117212	1.015528
	9600.0	1.115797	1.029669
	9800.0	1.114414	1.043745
	10000.0	1.113060	1.057755
	10200.0	1.111736	1.071700
	10400.0	1.110439	1.085577
	10600.0	1.109170	1.099389
	10800.0	1.107927	1.113133
	11000.0	1.106710	1.126110
1500.0	1500.0	1.325800	0.304850
	1750.0	1.316560	0.321280
	2000.0	1.308010	0.337740
	2250.0	1.300080	0.354220
	2500.0	1.292680	0.370720
	2750.0	1.285760	0.387240
	3000.0	1.279270	0.403780
	3250.0	1.273150	0.420330
	3500.0	1.267380	0.436890
	3750.0	1.261920	0.453460
	4000.0	1.256750	0.470030
	4250.0	1.251830	0.486600
	4500.0	1.247150	0.503170
	4750.0	1.242690	0.519730
	5000.0	1.238430	0.536280

[...]

Note: This PVT table being too long, only the beginning is provided here. However, if one needs whole table, please address a request to sylvain.ferro@gmail.com

Appendix D

Relative Permeability Include File

```
C *****Relative Permeability data*****

C      SWL     SWCR    SWU     SGL     SGCR    SGU     SOWCR   SOGCR
C     0.25    0.25       1       0       0    0.75    0.25     0.1
C OIL-WATER
C    Sw    Krw      Krow       Pcow   Pcowimb
SWT
    0.25  0.00000  1.00000       0       0
    0.30  0.00002  0.84983       0       0
    0.35  0.00032  0.70221       0       0
    0.40  0.00160  0.56116       0       0
    0.50  0.01235  0.31237       0       0
    0.55  0.02560  0.21029       0       0
    0.60  0.04743  0.12615       0       0
    0.70  0.12960  0.01869       0       0
    0.80  0.28920  0.00000       0       0
    0.90  0.56417  0.00000       0       0
    1.00  1.00000  0.00000       0       0
C OIL-GAS
C      Sg    Krg      Krog    Pcog
SGT
SGTR 0.00
    0.00  0.00000  1.00000       0
    0.02  0.00004  0.88997       0
    0.04  0.00030  0.78927       0
    0.05  0.00057  0.74225       0
    0.08  0.00230  0.61369       0
    0.10  0.00442  0.53778       0
    0.15  0.01440  0.37870       0
    0.16  0.01735  0.35168       0
    0.18  0.02433  0.30199       0
    0.20  0.03287  0.25775       0
    0.21  0.03776  0.23754       0
    0.24  0.05505  0.18398       0
    0.25  0.06173  0.16831       0
    0.26  0.06888  0.15366       0
    0.28  0.08464  0.12725       0
    0.30  0.10240  0.10438       0
    0.32  0.12220  0.08473       0
```

```
0.35  0.15583  0.06059      0
0.36  0.16810  0.05382      0
0.39  0.20810  0.03686      0
0.40  0.22250  0.03222      0
0.43  0.26887  0.02085      0
0.44  0.28538  0.01783      0
0.45  0.30240  0.01515      0
0.46  0.31994  0.01277      0
0.47  0.33798  0.01069      0
0.50  0.39506  0.00592      0
0.51  0.41505  0.00475      0
0.54  0.47776  0.00225      0
0.55  0.49954  0.00168      0
0.57  0.54433  0.00087      0
0.59  0.59068  0.00039      0
0.60  0.61440  0.00024      0
0.61  0.63846  0.00013      0
0.62  0.66285  0.00006      0
0.63  0.68754  0.00002      0
0.64  0.71251  0.00001      0
0.65  0.73776  0.00000      0
0.70  0.86724  0.00000      0
0.75  1.00000  0.00000      0
```

Appendix E

Pipe-It Model

E.1 Master Project

Fig. E.1 shows first level of Master project.

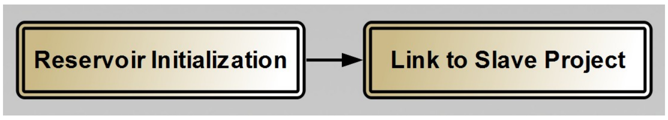


Fig. E.1: First level of Master project comprising two different composites.

E.1.1 Reservoir Initialization composite

Fig. E.2 shows what is inside Reservoir Initialization composite.

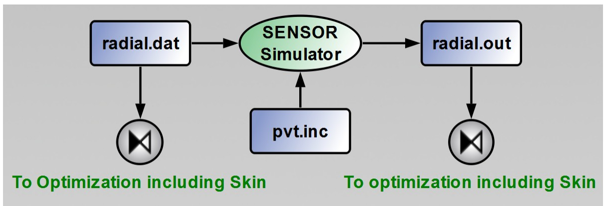


Fig. E.2: Organization of the inside of Reservoir Initialization composite which launches SENSOR reservoir simulation.

E.1.2 Link to Slave Project composite

Fig. E.3 shows the organization of second composite of Master project which is in charge of making the connection with Slave project.

E.2 Slave Project

Fig. E.4 represents first level of Slave project.

E.2.1 Reservoir Simulator composite

Fig. E.5 shows the composite where reservoir simulation is executed. The only difference with Reservoir Initialization composite (Master project) is that simulation results are converted to Streamz format in "Convert SENSOR Well Rates by Time Step to STREAMZ Format" composite.

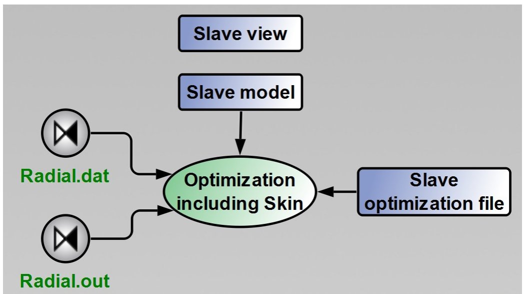


Fig. E.3: Organization of second composite in Master project, Link to Slave project, triggering Slave project run and optimization.

Fig. E.4: First level of Slave project comprising three different composites.

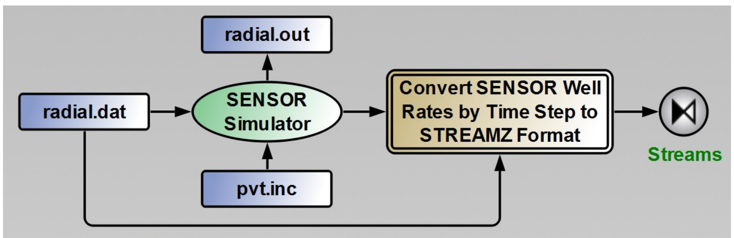


Fig. E.5: Reservoir Simulator composite which launches SENSOR reservoir simulation and converts SENSOR output into *STREAMZ* format compatible with Pipe-It.

E.2.1.1 Convert SENSOR Well Rates by Time Step to STREAMZ Format composite

Fig. E.6 details the organization of "Convert SENSOR Well Rates by Time Step to STREAMZ Format" composite.

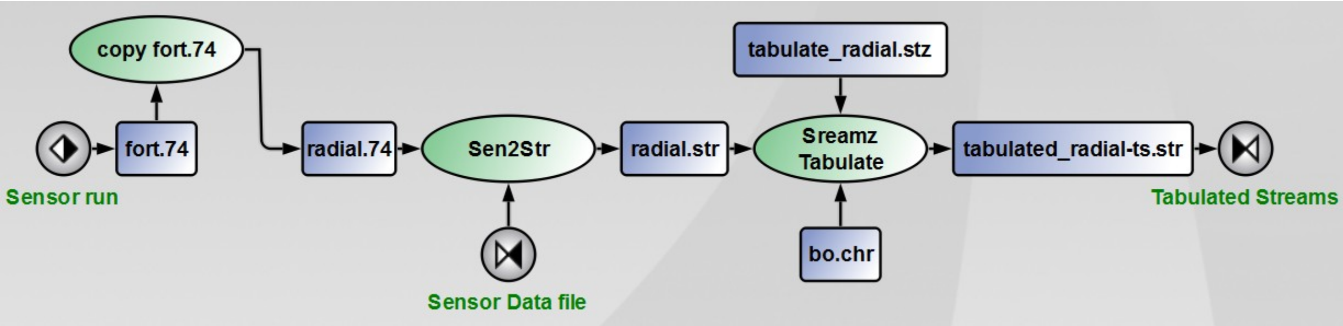


Fig. E.6: Sub-composite of Reservoir Simulator composite showing the details on how SENSOR output is converted into *STREAMZ* format.

<u>**Tabulate Radial streamz file**</u>

```
Include bo.chr
StreamFile INFILE  Input  radial.str
StreamFile OUTFILE Output tabulated_radial-ts.str

Tabulate WELL and T1 days and T2 days

streamfile INFILE close
streamfile OUTFILE close
```

<u>**BO characterization file**</u>

```
* ---------------------------------------------------------
* This is a "characterization" file, defining a
* fluid characterization.
*
* This particular characterization named "BO_Char",
* contains two "components" named SO and SG
* (surface oil and surface gas components respectively)
*
* Note that all streams must be associated
* with a defined characterization.
* ----------------------------------------------------------

CHAR "BO_Char"  ; Name of characterization
NAME
SO
SG
END
```

E.2.2 Products Separation composite

Fig. E.7 displays the inside of second composite of Slave project.

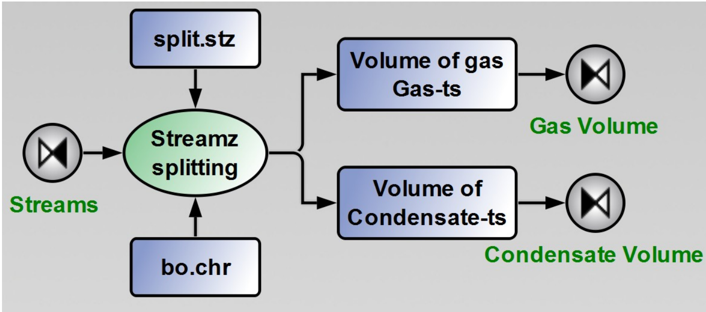


Fig. E.7: Products Separation composite. Hydrocarbons stream is divided in two streams, Oil stream and Gas stream, using a Black-Oil characterization.

Split streamz file

```
Include bo.chr

CHAR Gas
NAME
Gas-Mcf

END

CHAR Oil
NAME
Oil-STB

END

RESTORE Gas
CONVERT BO_Char from amounts to volume
SPLIT SG  Gas-Mcf  1

END

RESTORE Oil
CONVERT BO_Char from amounts to volume
SPLIT SO  Oil-STB  1

END

RESTORE BO_Char
StreamFile INFILE  Input  tabulated_radial-ts.str
```

```
RESTORE Gas
StreamFile OUTFILE Output GasVolume-ts.str

DOMAIN TIME T1 T2
COPY WEIGH TIME (DAYS)

streamfile OUTFILE close

RESTORE Oil
StreamFile OUTFILE Output OilVolume-ts.str

DOMAIN TIME T1 T2
COPY WEIGH TIME(DAYS)

streamfile OUTFILE close
streamfile INFILE close
```

E.2.3 Economic Calculations composite

Fig. E.8 shows the inside of Economic Calculations Composite. It is divided in two composites which are detailed below.

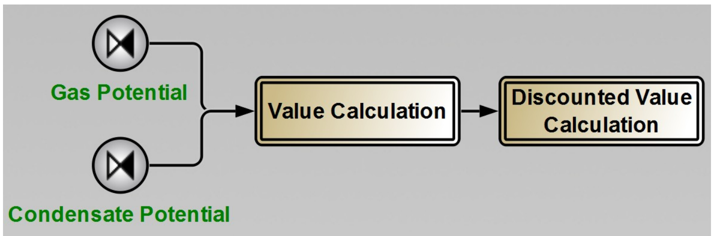


Fig. E.8: Economic Calculations composite which is itself divided in two sub-composites.

E.2.3.1 Value Calculation composite

Fig. E.9 shows how product value is calculated.

Gas Value streamz file

```
DEFINE USD/MCF-INITIAL 6.25

Include gas-price.cnv

RESTORE Gas
StreamFile INFILE  Input  GasVolume-ts.str

RESTORE value
StreamFile OUTFILE Output Gas-value-ts.str
```

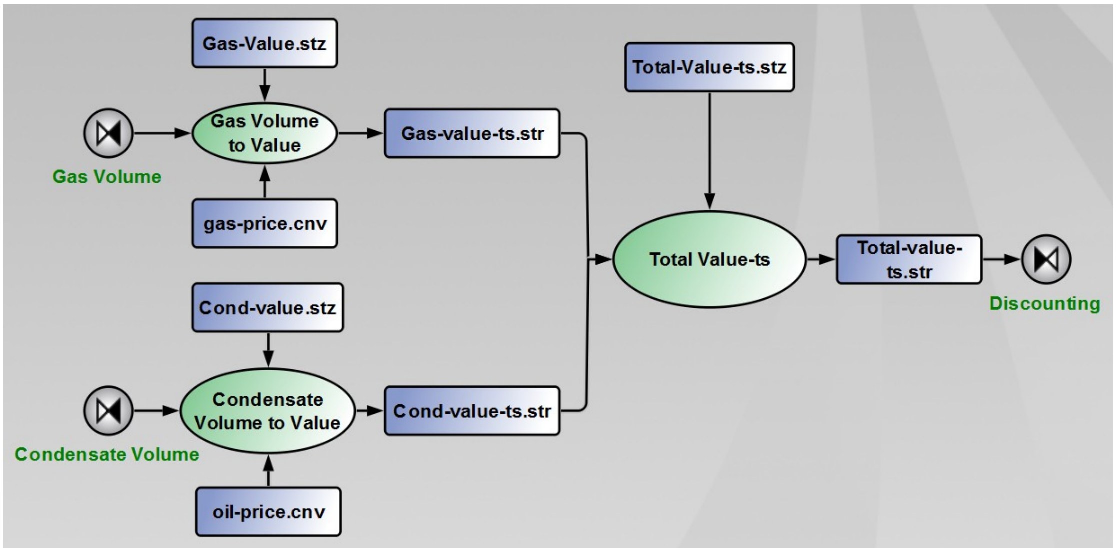


Fig. E.9: First sub-composite, Value Calculation. Based on price assumptions for oil and gas, it returns a total value (not discounted) per time step called "Total-value-ts.str".

```
COPY SCALE ?USD/MCF-INITIAL?

StreamFile INFILE CLOSE
StreamFile OUTFILE CLOSE
```

<u>**Gas Price conversion file**</u>

```
CHAR Gas
NAME
Gas

CHAR VALUE
NAME
USD

VARIABLE T2 TIME

CONVERT Gas FROM VOLUME TO AMOUNT

SET T2  0 YEAR
SPLIT Gas  USD      1.000
SET T2  1 YEAR
SPLIT Gas   USD     1.000
SET T2  2 YEAR
SPLIT Gas   USD     1.025
SET T2  3 YEAR
SPLIT Gas   USD     1.050
```

```
SET T2  4 YEAR
SPLIT Gas   USD     1.075
SET T2  5 YEAR
SPLIT Gas   USD     1.100
SET T2  6 YEAR
SPLIT Gas   USD     1.125
SET T2  7 YEAR
SPLIT Gas   USD     1.150
SET T2  8 YEAR
SPLIT Gas   USD     1.175
SET T2  9 YEAR
SPLIT Gas   USD     1.200
SET T2 10 YEAR
SPLIT Gas   USD     1.225
SET T2 11 YEAR
SPLIT Gas   USD     1.250
SET T2 12 YEAR
SPLIT Gas   USD     1.275
SET T2 13 YEAR
SPLIT Gas   USD     1.300
SET T2 14 YEAR
SPLIT Gas   USD     1.325
SET T2 15 YEAR
SPLIT Gas   USD     1.350
SET T2 16 YEAR
SPLIT Gas   USD     1.375
SET T2 17 YEAR
SPLIT Gas   USD     1.400
SET T2 18 YEAR
SPLIT Gas   USD     1.425
SET T2 19 YEAR
SPLIT Gas   USD     1.450
SET T2 20 YEAR
SPLIT Gas   USD     1.475
```

Condensate Value streamz file

```
DEFINE USD/BBL-INITIAL 40

Include oil-price.cnv

RESTORE Oil
StreamFile INFILE  Input  OilVolume-ts.str

RESTORE value
StreamFile OUTFILE Output Cond-value-ts.str

COPY SCALE ?USD/BBL-INITIAL?
```

```
StreamFile INFILE CLOSE
StreamFile OUTFILE CLOSE
```

Oil price conversion file

```
CHAR Oil
NAME
Cond-STB

CHAR VALUE
NAME
USD

VARIABLE T2 TIME

CONVERT Oil FROM VOLUME TO AMOUNT

SET T2  0 YEAR
SPLIT Cond-STB  USD      1.000
SET T2  1 YEAR
SPLIT Cond-STB   USD     1.000
SET T2  2 YEAR
SPLIT Cond-STB   USD     1.025
SET T2  3 YEAR
SPLIT Cond-STB   USD     1.050
SET T2  4 YEAR
SPLIT Cond-STB   USD     1.075
SET T2  5 YEAR
SPLIT Cond-STB   USD     1.100
SET T2  6 YEAR
SPLIT Cond-STB   USD     1.125
SET T2  7 YEAR
SPLIT Cond-STB   USD     1.150
SET T2  8 YEAR
SPLIT Cond-STB   USD     1.175
SET T2  9 YEAR
SPLIT Cond-STB   USD     1.200
SET T2 10 YEAR
SPLIT Cond-STB   USD     1.225
SET T2 11 YEAR
SPLIT Cond-STB   USD     1.250
SET T2 12 YEAR
SPLIT Cond-STB   USD     1.275
SET T2 13 YEAR
SPLIT Cond-STB   USD     1.300
SET T2 14 YEAR
SPLIT Cond-STB   USD     1.325
```

```
SET T2 15 YEAR
SPLIT Cond-STB   USD     1.350
SET T2 16 YEAR
SPLIT Cond-STB   USD     1.375
SET T2 17 YEAR
SPLIT Cond-STB   USD     1.400
SET T2 18 YEAR
SPLIT Cond-STB   USD     1.425
SET T2 19 YEAR
SPLIT Cond-STB   USD     1.450
SET T2 20 YEAR
SPLIT Cond-STB   USD     1.475
```

Total Value per time step streamz file

```
DEFINE TVAR T2
DEFINE CURRENCY USD
DEFINE VALUECHAR VALUE

CHAR ?VALUECHAR?
NAME
?CURRENCY?

VARIABLE TOTAL STRING
SET TOTAL TOTAL

StreamFile INFILE1 Input Cond-value-ts.str
StreamFile INFILE2 Input Gas-value-ts.str

; Total (undiscounted) Value by Time Step
StreamFile OUTFILE Output Total-value-ts.str
TABULATE T1 DAYS AND T2 DAYS COLLATE
StreamFile OUTFILE CLOSE

StreamFile INFILE1 CLOSE
StreamFile INFILE2 CLOSE
```

E.2.3.2 Discounted Value Calculation composite

Fig. E.10 details how value is discounted to get Total Discounted Value which is our objective function for optimization.

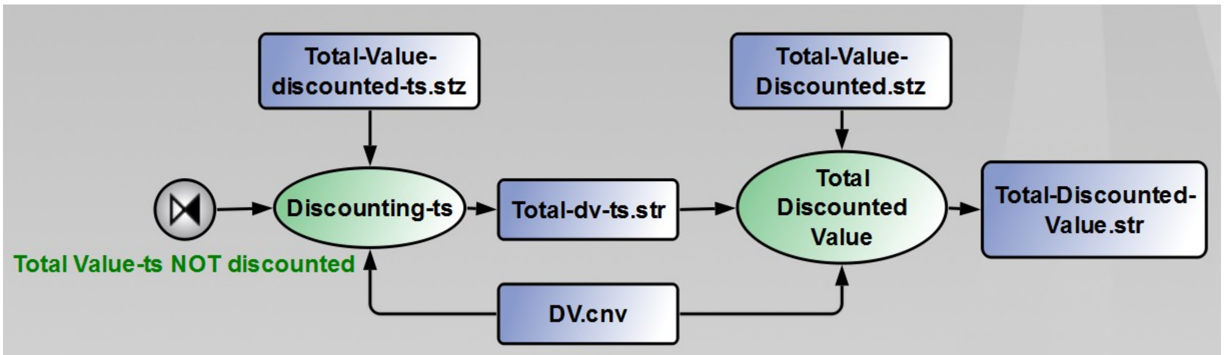


Fig. E.10: Second sub-composite, Discounted Value Calculation. Given a discount factor value, it calculates the total discounted value of the project which is the objective function for optimization.

Total Value Discounted per time step streamz file

```
DEFINE TVAR T2
DEFINE CURRENCY USD
DEFINE VALUECHAR VALUE

CHAR ?VALUECHAR?
NAME
?CURRENCY?

VARIABLE TOTAL STRING
SET TOTAL TOTAL

; Total Discouned Value by Time Step

Include npv.cnv
RESTORE ?VALUECHAR?
StreamFile INFILE  Input Total-value-ts.str
RESTORE NPV
StreamFile OUTFILE Output Total-npv-ts.str
VARIABLE DCF REAL
SET DCF 10
COPY

StreamFile INFILE  CLOSE
StreamFile OUTFILE CLOSE
```

Total Value Discounted streamz file

```
DEFINE TVAR T2
DEFINE CURRENCY USD
DEFINE VALUECHAR VALUE

CHAR ?VALUECHAR?
NAME
?CURRENCY?

VARIABLE TOTAL STRING
SET TOTAL TOTAL

; Total Discounted Value
Include npv.cnv
RESTORE NPV
StreamFile INFILE  Input  Total-npv-ts.str
StreamFile OUTFILE Output Total-npv.str
TABULATE
;DISPLAY TOTAL AND TIME (YEARS) , COLLATE
```

Discounted Value conversion file

```
; NPV.CNV
; STREAMZ SPLIT FACTORS FOR NET PRESENT VALUE CONVERSION
; -----------------------------------------------------
; TIME MAXIMUM ...........................     50.00
; TIME INCREMENT .........................      1.00
; DISCOUNT FACTOR MAXIMUM ................     30.00
; DISCOUNT FACTOR INCREMENT...............      1.00
;
; Note: About <0.5% error with linear interpolation
;        for Time and DCF increments of 1.

RESTORE ?VALUECHAR?

CHAR NPV
 NAME
 ?CURRENCY?

VARIABLE DCF REAL
VARIABLE ?TVAR?  TIME

ECHO OFF

CONVERT ?VALUECHAR? FROM AMOUNT TO AMOUNT

 SET DCF =        10.00  ?TVAR?  =        0.00  YEAR
```

```
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.10000000E+01
SET DCF =        10.00  ?TVAR?  =          1.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.90909091E+00
SET DCF =        10.00  ?TVAR?  =          2.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.82644628E+00
SET DCF =        10.00  ?TVAR?  =          3.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.75131480E+00
SET DCF =        10.00  ?TVAR?  =          4.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.68301346E+00
SET DCF =        10.00  ?TVAR?  =          5.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.62092132E+00
SET DCF =        10.00  ?TVAR?  =          6.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.56447393E+00
SET DCF =        10.00  ?TVAR?  =          7.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.51315812E+00
SET DCF =        10.00  ?TVAR?  =          8.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.46650738E+00
SET DCF =        10.00  ?TVAR?  =          9.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.42409762E+00
SET DCF =        10.00  ?TVAR?  =         10.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.38554329E+00
SET DCF =        10.00  ?TVAR?  =         11.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.35049390E+00
SET DCF =        10.00  ?TVAR?  =         12.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.31863082E+00
SET DCF =        10.00  ?TVAR?  =         13.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.28966438E+00
SET DCF =        10.00  ?TVAR?  =         14.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.26333125E+00
SET DCF =        10.00  ?TVAR?  =         15.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.23939205E+00
SET DCF =        10.00  ?TVAR?  =         16.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.21762914E+00
SET DCF =        10.00  ?TVAR?  =         17.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.19784467E+00
SET DCF =        10.00  ?TVAR?  =         18.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.17985879E+00
SET DCF =        10.00  ?TVAR?  =         19.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.16350799E+00
SET DCF =        10.00  ?TVAR?  =         20.00  YEAR
SPLIT  ?CURRENCY?  ?CURRENCY?                                        0.14864363E+00
```

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SI Metric Conversion Factors

bbl/d x 1.589 873	E-01 =m ^{3}/d
ft x 3.048*	E-01 = m
ft^3/d x 2.831 685	E-02 =m ^{3}/d
lbm/ft^3 x 1.601 846	E+01 = kg/m^3
in x 2.54*	E-01=E+00 = cm
bar x 1.0*	E+05 = Pa
psi x 6.894 757	E+00 = kPa
cp x 1.0*	E-03 = Pa.s
D x 1.0	E-13 = m^2

*Conversion factor is exact

Nomenclature

B	Formation volume factor
bbl	Barrels, $[L^3]$
BHP	Bottom Hole Pressure,$[F/L^2]$
CPU	Central Processing Unit
d	day, $[T]$
DCF	Discount Factor, %
ΔP	Pressure drop,$[F/L^2]$
Dq	Rate dependent skin factor
GOR	Gas Oil Ratio,$[L^3/L^3]$
GUI	Graphical User Interface
H	Thickness, [L]
HTE	Heel to Toe Effect
ICD	Inflow Control Device
ICV	Interval Control Valve
K	Permeability, $[L^2]$
K_r	Relative permeability
μ	Viscosity, [M/Lt]
$mscf$	thousand standard cubic feet, $[L^3]$
$MSTB$	thousand stock tank barrels, $[L^3]$
NPV	Net Present Value
OGR	Oil Gas Ratio,$[L^3/L^3]$
Φ	Porosity, %

P	Pressure, $[F/L^2]$
$PAVGHC$	Hydrocarbon Pore Volume Average Pressure, $[F/L^2]$
P_{dp}	Dew point pressure, $[F/L^2]$
P_r	Initial reservoir pressure, $[F/L^2]$
PVT	Pressure Volume Temperature
Q, q	Flow rate, $[L^3/T]$
r_e	External boundary radius, $[L]$
r	radius , $[L]$
r_s	Solution oil gas ratio, $[L^3/L^3]$
r_w	Wellbore radius, $[L]$
ρ	Density of produced fluid, $[M/L^3]$
S	Skin factor
SAS	Stand-Alone Screen
S	Saturation, %
$TotalDiscVal$	Total Discounted Value, $
USD	United State Dollar, $
VIS	Viscosity, $[L^2/T]$
Z	Depth, $[L]$

Subscripts/Superscripts

1	Related to layer 1
2	Related to layer 2
c	Critical
g	Gas
h	Horizontal
i	Irreducible
init	Initial
n	Analytical relative permeability exponent
o	Oil
r	Residual (when associated with saturations)
r	Reservoir (when associated with pressures)
T	Total
ts	Time step
v	Vertical

w	Water
x	Horizontal axis
y	Horizontal axis
z	Vertical axis