Prepared by:
Mujahid Mirghani Bashier
Mohamed Ibrahim Alsheikh
Mohamed Abdalazim Musa

Supervisor:
Prof. Hassan B. Nimir

Co-Supervisor:
Eng. Ali Albadri
Eng. Ahmed Fadul

THERMAL RATE ALLOCATION TECHNIQUE

This graduation project is to be submitted partially to fulfill the requirement of B.Sc. (honor degree) program in petroleum and natural gas engineering.
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Acknowledgement:

First of all thanks to Allah who alone do we worship and ask for help and guidance, Thanks for giving us enough patience and power to overcome all obstacles.

Thanks to our parents and families for their endless support and their blessings. Thank you for praying to us.

We place our sincere gratitude to all our professors specially Dr. Hassan Bashier Nimir for encouraging us.

Special thanks for Engineers: Ali Albadri, Ahmed Fadul and Mazin Zainalabdin for providing the required help generously.
Abstract:

One of the most important parameter is to identify the type of the fluid being produced and its rate. This problem is easier to be detected in single layer production wells than in comingled wells because the production from different zones is delivered to the surface in matter of sum through one conduit.

Rate allocation is defined as determination of production rates of each layer in single well producing in commingled manner. Rate allocation is a very major concern to specify unwanted fluids production. Also, it is useful in identifying the participation percentage of each zone moreover; it is a major factor to develop a reservoir models history matching for those reservoirs producing in a commingled manner.

Thermal Rate Allocation is performed through equations that relate temperature with flow rate. Those equations have been derived based on mass balance, energy balance and many assumptions.

A fiber optical distributed temperature sensing system can provide a reliable down-hole temperature values at various periods of time a long wellbore length (temperature profile) rather than measuring a single value of temperature causatively, without restricting production.
الخلاصة

تعتبر مشكلة تحديد نوع ومعدل إنتاج السوائل المنتجة إحدى أهم العوامل في الصناعة النفطية. التفاعل مع هذه المشكلة يعد أصعب في الأبار ذات الإنتاج المجمع من عدة طبقات من ما هو الحال عليه في الأبار التي تنتج من طبقة واحدة لأن الإنتاج من عدة طبقات يكون مجمعًا عبر قناة واحدة (أربوب واحد).

مصطلح تحديد التدفق الإنتاجي يعرف على أنه تحديد أو حساب معدلات الإنتاج لكل طبقة في الأبار التي تنتج بصور مجمعة. يعتبر تحديد التدفق الإنتاجي مهما في تحديد الطرقات التي تنتج نسبا أعلى من الموائع غير المرغوب فيها. تحدد نسبة مشاركة كل طبقة في الإنتاج الكلي لذا يعتبر أيضا عاملًا مهمًا في إنشاء تطابق تاريخي مع بيانات سابقة للمكمن الذي تنتج بصورة مجمعة.

تحديد التدفق الإنتاجي بواسطة الحرارة هو إحدى طرق تحديد معدل إنتاج الطرقات المختلفة التي تنتج بصورة مجمعة. ويتم ذلك عبر معادلات تربط درجات الحرارة ومعدل الإنتاج. هذه المعادلات تم إستنتاجها وفقاً وبناءً على قواعد حفظ الكتلة، قواعد حفظ الطاقة وعدد إفتراضات أخرى.

نظام الألياف الضوئية لاستشعار درجة الحرارة يعطي قيمة موثوقة لدرجات الحرارة داخل البئر في فترة زمنية مختلفة لجمال طول البئر وذلك من غير أن تتسبب أي إعاقة للإنتاج.
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</tr>
<tr>
<td>C</td>
<td>Conversion Factor For Darcy Law Equals $1.21 \times 10^{-3}$</td>
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<tr>
<td>$C_p$</td>
<td>Specific Heat, $BTU/lbm - F$</td>
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<tr>
<td>$C_{pg}$</td>
<td>Specific Heat of Gas, $BTU/lbm - F$</td>
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<tr>
<td>$C_{pmix}$</td>
<td>Mixed Specific Heat, $BTU/lbm - F$</td>
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<tr>
<td>$C_{pw}$</td>
<td>Specific Heat of water, $BTU/lbm - F$</td>
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<tr>
<td>d</td>
<td>Inner Diameter of The Tubing, $ft$</td>
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<tr>
<td>DTS</td>
<td>Distributed Temperature Sensors</td>
</tr>
<tr>
<td>f</td>
<td>Friction Factor</td>
</tr>
<tr>
<td>$F_c$</td>
<td>Constant Given By Equation (B.39) &amp; Equation (B.40)</td>
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<td>$G_1, G_2$</td>
<td>Constants Given By Equation (B.30-a) and Equation (B.30-b)</td>
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<td>$G_T$</td>
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<tr>
<td>$\dot{H}$</td>
<td>Specific Enthalpy, $BTU/lb$</td>
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<tr>
<td>h</td>
<td>Reservoir Thickness, $ft$</td>
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<tr>
<td>i</td>
<td>Index for Number of Temperature Measurements in The Producing Zones</td>
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<tr>
<td>k</td>
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<td>$K_{an}$</td>
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<td>$K_{anw}$</td>
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<tr>
<td>$K_T$</td>
<td>Rock Thermal Conductivity, $BTU/D - ft - F$</td>
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<td>L</td>
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<td>$M_w$</td>
<td>Molecular Weight, $lb/mole$</td>
</tr>
<tr>
<td>n</td>
<td>Number of division or Number of Temperature Measurements Inside Producing Zones</td>
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<tr>
<td>OFC</td>
<td>Optical Fiber Control</td>
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<tr>
<td>P.E.</td>
<td>Potential Energy</td>
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<tr>
<td>P</td>
<td>Pressure, $psi$</td>
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<tr>
<td>$P_{pc}$</td>
<td>Pseudo Critical Pressure, $psi$</td>
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<td>( P_e )</td>
<td>Reservoir Pressure, psi</td>
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<tr>
<td>( PLT )</td>
<td>Production Logging Tool</td>
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<td>( Q )</td>
<td>Heat Transfer Between Fluid &amp; Surrounding Area, BTU/lbm</td>
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<td>( q )</td>
<td>Fluid Flow Rate, bbl/d</td>
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<td>( q_1 )</td>
<td>Flow Rate From The Lower Zone</td>
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<tr>
<td>( q_2 )</td>
<td>Flow Rate From The Upper Zone</td>
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<tr>
<td>( q_g )</td>
<td>Gas Flow Rate, ft³/d</td>
</tr>
<tr>
<td>( q_{g1} )</td>
<td>Gas Flow Rate From Lower Zone, ft³/d</td>
</tr>
<tr>
<td>( q_{g2} )</td>
<td>Gas Flow Rate From upper Zone, ft³/d</td>
</tr>
<tr>
<td>( q_{gt} )</td>
<td>Total Gas Flow Rate From The Two Zones, ft³/d</td>
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<tr>
<td>( q_w )</td>
<td>Water Flow Rate, STB/d</td>
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<tr>
<td>( q_{w1} )</td>
<td>Water Flow Rate From Lower Zone, STB/d</td>
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<tr>
<td>( q_{w2} )</td>
<td>Water Flow Rate From upper Zone, STB/d</td>
</tr>
<tr>
<td>( q_{wt} )</td>
<td>Total Water Flow Rate From The Two Zones, STB/d</td>
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<tr>
<td>( R )</td>
<td>Universal Gas Constant = 10.73 psi ft³/mole. R</td>
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<td>( r )</td>
<td>Radius, in</td>
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<td>( r_c )</td>
<td>Inside Casing Radius, in</td>
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<td>( r_o )</td>
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<td>( r_{to} )</td>
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<td>( r_D )</td>
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<tr>
<td>( r_e )</td>
<td>Drainage Radius, ft</td>
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<tr>
<td>( r_eD )</td>
<td>Dimensionless Drainage Radius</td>
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<td>( r_{wb} )</td>
<td>Wellbore Radius, ft</td>
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<td>( T )</td>
<td>Temperature, °R</td>
</tr>
<tr>
<td>( t )</td>
<td>Time, hr</td>
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<tr>
<td>( t_D )</td>
<td>Dimensionless Time</td>
</tr>
<tr>
<td>( T_e )</td>
<td>Earth Temperature, F</td>
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<td>( T_{eD} )</td>
<td>Earth Dimensionless Temperature</td>
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<td>( T_{ei} )</td>
<td>Earth Temperature at Any Depth and Far Away From The Well, F</td>
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<td>( T_{ebh} )</td>
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<td>$T_{fbh}$</td>
<td>Fluid temperature at the bottom hole of the well, $F$</td>
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<td>$T_h$</td>
<td>Temperature at the cement/earth interface, $F$</td>
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<td>$T_{pc}$</td>
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<td>$T_{pr}$</td>
<td>Pseudo Reduced Temperature</td>
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<tr>
<td>$T_{ref}$</td>
<td>Reference Temperature</td>
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<td>$u$</td>
<td>Velocity of Flow Through Porous Medium (Darcy Velocity), ft/sec</td>
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<td>$U$</td>
<td>Overall Heat Transfer Coefficient, $BTU/D-\text{ft}^2/F$</td>
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<td>$V$</td>
<td>Specific Volume, $ft^3/lbm$</td>
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<td>$v$</td>
<td>Velocity, ft/sec</td>
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<td>$w$</td>
<td>Mass Flow Rate, ft/sec</td>
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<td>$w_t$</td>
<td>Total Production at Each Interval Inside The Producing Zone, ft/sec</td>
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<td>$Z$</td>
<td>Compressibility Factor</td>
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<td>$\alpha$</td>
<td>Thermal diffusivity of earth, $ft^2/hr$</td>
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<td>$\beta$</td>
<td>Thermal Fluid Expansion, °F$^{-1}$</td>
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<td>$\beta_g$</td>
<td>Thermal gas Expansion, °F$^{-1}$</td>
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<td>Mixed Thermal Expansion, °F$^{-1}$</td>
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<td>$\gamma_g$</td>
<td>Gas specific Gravity (air=1)</td>
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<td>$\gamma_w$</td>
<td>Water Specific Gravity</td>
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<tr>
<td>$\theta$</td>
<td>Angle of inclination of the well with horizontal, deg.</td>
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<tr>
<td>$\lambda$</td>
<td>Constant Given By Equation (B.28-b)</td>
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<td>$\mu$</td>
<td>Viscosity, $cp$</td>
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<td>Gas and Water Viscosities Respectively, $cp$</td>
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<td>$\mu_{mix}$</td>
<td>Mixture Viscosity, $cp$</td>
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<td>$\mu_{jt}$</td>
<td>Joule Thomson Effect, $F/psi$</td>
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<td>$\mu_{jtg}$</td>
<td>Gas Joule Thomson Effect, $F/psi$</td>
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<td>$\mu_{jtw}$</td>
<td>Water Joule Thomson Effect, $F/psi$</td>
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<tr>
<td>$\mu_{jtm}$</td>
<td>Mixture Joule Thomson Effect, $F/psi$</td>
</tr>
<tr>
<td>$\rho$</td>
<td>Density, $lbm/ft^3$</td>
</tr>
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<td>$\rho_e$</td>
<td>Earth Density, $lbm/ft^3$</td>
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<td>$\rho_g$</td>
<td>Gas Density, $lbm/ft^3$</td>
</tr>
<tr>
<td>$\rho_w$</td>
<td>Water Density, $lbm/ft^3$</td>
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<tr>
<th>Symbol</th>
<th>Definition</th>
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<tr>
<td>( p_{\text{mix}} )</td>
<td>Mixed Density, ( \text{lbm/ft}^3 )</td>
</tr>
<tr>
<td>( \phi )</td>
<td>Porosity, fraction</td>
</tr>
<tr>
<td>( \omega )</td>
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Chapter 1: Introduction:

Petroleum can be taken as profit making source of energy for long time, Petroleum represents the most important source of energy during the second war (Yusgiantoro, 2004)

Nowadays oil denotes 40% of the world energy consumption because petroleum is irreplaceable saleable product, with a large number of byproducts (Yusgiantoro, 2004)

Production engineer role is to exceed petroleum production by applying techniques lead to maximizing produced amount in economically conditions, understanding and explanation of production system can help to optimize the production rate (Boyun GUO, 2010)

1-1 Definition of the problem:
Observation, supervision, problems detection and problems analysis of petroleum wells take a part in production management, business and operations. Many parameters are involved in the production operation; one of the most important parameter is to identify the type of the fluid being produced and its rate (Reda Rabie, 2010).

This problem is easier to be detected in single layer production wells i.e. wells with conventional completion than in comingled wells because the production from different zones is delivered to the surface in matter of sum through one conduit, thus relating them to their origin layer quantitatively and qualitatively represents a severe issue (Reda Rabie, 2010).
1-2 Well completion:-

It is the process, by which the producible zones are prepared to taken into production, when a well already has been drilled to the total depth, cased and cemented, engineers must applying completion process by inserting and installing equipment and tools which help optimization of production down and along a portion of the hole. (Flatem, 2012)

The category of completion to use relies on the geological and structural properties of the reservoir, and mineralization type. There are two main type of completion:— (M.J.etal, 1998)

1- Open hole completion
2- Cased hole completion:— include two major configuration:—
   a) Conventional completion.
   b) Smart (intelligent) completion: Smart completion is firstly applied in 1990s to allow control of production to be directly taking place inside the well, to avoid repairing job which can cause additional cost and interrupt of continuity of production process.
Both intelligent and conventional completion can be applied to multiple zones production.
1-3 Multi zones production:

Refers to production from more than one zone so as to allow zones fluids to flow to the surface. (M.J. et al, 1998)

1-4 Methods of extracting fluids from multiple reservoirs:-(R. Sankar, September 30, 2010)

1- Completion of the reservoirs in sequence from the bottom layer to the top.

2- Production of fluids simultaneously from all layers in a segregated manner by using multi production strings.

3- Commingled production in which we produce fluids from all layers in an unsegregated manner (through one conduit).

1-5 Commingled production:

Production of petroleum from more than one zone (layer) through the same production conduit called commingled production (D. Perrin, 1999)

Commingling can be done at any particular stage during well lifetime from the early beginning of production to the late stage of recompletion (Slocomb, July 8, 2011)
Thermal rate allocation Technique

1-5-1 Conditions to use: (Slocomb, July 8, 2011)

1. To increase amount of producible hydrocarbons.
2. To increase the chances of production from noncommercial zones.
3. Support lifting fluids in the production conduit by the combined pressures.

Figure 2: commingled production (Slocomb, July 8, 2011)
1-5-2 Considerations to be taken in commingling: (R.Sankar, September 30, 2010)

1. Allocate the production of each layer (to refer production contribution to corresponding layer).
2. To avoid cross-flow between layers.
3. To eliminate production of undesired fluids (gas or water).
4. Assuring flow of fluids by assuring reliable completion practices.
5. To be sure that all fluids can be produced simultaneously without significant problems.

1-5-3 Information and data required: (R.Sankar, September 30, 2010)

There are many required information in order to apply commingling:
1. Number of layers and their depths and thicknesses.
2. Expected production rates from each layer.
3. Detailed information about each layer such as: productivity index PI, oil originally in place OOIP and pressure corresponding to each layer.
4. The procedure of allocating production of each layer in order to manage layers.
5. Methods of avoiding and dealing with cross-flow and undesired effluents (water and/or gas).
6. Detailed description about control and measurements equipment.
7. Completion equipment installation plan.

1.6 Objective:
Based on the above discussion, the objective this work is to:

- Establish and construct accurate, fast allocate flow rates continuously.
- Checking the validity of the method and sensitivity to inaccuracy of the input data.
- Initiating an economic evaluation of the method.
Chapter 2: Literature review:

2-1 Definition of rate allocation:

Defined as determination of production rates of each layer in single well producing in commingled manner. (Wang, March, 2003).

In case of multi zone with multi phases being produced in commingled manner, rate allocation is a very major concern to specify unwanted fluids production and thus perform a work-over job (shut off) to the zone of that unwanted production. Allocation is also useful in identifying the participation percentage of each zone and thus specifying of candidate zones for stimulation can be easily done. (Reda Rabie, 2010).

Moreover, rate allocation is a major factor to develop a reservoir models history matching for those reservoirs producing in a commingled manner. This can be done for both wells with commingled production at surface and wells with intelligent completions having production in a commingled manner at the bottom of the well. (Luigi Saputelli, 2011)

2-2 Difference between rate allocation and rate estimation:

We must differentiate between rate allocation and rate estimation:

Rate estimation is predicting of quantity of mass or volume of fluids from each layer in an intelligent well, while flow allocation is the part of total volume and mass measurement of fluids based on predicted contribution of each layer. (R. Sankar, September 30, 2010)
Thermal rate allocation Technique

2-3 several methods of rate allocation:

2-3-1 flow capacity method (KH method)
Determine the allocation factor to know the contribution for each zone based on the equation:

\[
Allocation \ factor \ (F) = \frac{(kh)_i}{\sum_{i=1}^{n} (kh)_i} \quad (2.1)
\]

This gives a quantitative estimate of the amount of fluid participate from individual zone in the total production.
This method gives a very roughly estimate of the rate, associated with drastic error. Thus it is not advised.

2-3-2 geochemical method
Development of field strategies requires operators to define which layer yet to be produced and which one layer is producing with commercial or non-commercial production, in commingled production this problem is a major concern, a new technology called geochemical allocation has been developed to identify production zones and their corresponding rates. (MARK A. MCCAFFREY et al., March, 2013)

Chemistry fingerprinting method of allocating rate in commingled well is used for more than 20 years in order to allocate multiphase wells and fields. (MARK A. MCCAFFREY et al., March, 2013)

Peak ratios developed from gas chromatograph are used to specify quantitatively the participation of fluids produced from each layer in total commingled production. Analysis of a stream by Gas Chromatograph provides values for more than 1000 of originally existing compounds. (MARK A. MCCAFFREY et al., March, 2013)

The multiplicity of any participation of those components is used as locater for commingled stream produced, and this multiplicity of each component is proportional to the peak point height on graph delivered by gas chromatograph. (MARK A. MCCAFFREY et al., March, 2013)
In case of having two commingled layers production, the percentage of participation of each layer can be specified by using the differences in chemical composition of the pure samples of fluids from each layer.\(^{(\text{MARK A. MCCAFFREY et al., March, 2013})}\)

In basic method of allocation, gas chromatograph peak ratios representing variations in chemical composition are measured in the end-member oils, and in both different synthetic mixtures of the end-member oils and in commingled oil. Then these data is expressed mathematically to represent the participation of the relative end-member oil in the composition of the commingled oil.\(^{(\text{MARK A. MCCAFFREY et al., March, 2013})}\)

The equation of gas chromatograph rate allocation determination method is defined as follow:

\[
Y = \beta_1 X_1 + \beta_2 X_2 + \ldots + \beta_m X_m
\]  \hspace{1cm} (2.2)

Where \(Y\) is defined gas chromatograph peak height measured in the trace of commingled oil, \(X\) is gas chromatograph peak heights of the matching peak in the \(m\) end-members oils being commingled and \(\beta\) is the rate allocation factor.\(^{(\text{MARK A. MCCAFFREY et al., March, 2013})}\)

The essential of rate allocation by the gas chromatograph is to determine the values of \(\beta.\)\(^{(\text{MARK A. MCCAFFREY et al., March, 2013})}\)
2.3.2.1 causes of error:
There are many causes of error in this method such as:

- Error caused during measuring the height of each gas chromatograph peak (analytical error).
- Error with the potential contamination of gas chromatograph peaks.
- Non ideality of samples also causes errors.
Thermal rate allocation Technique

2-3-2-2 Disadvantages of geochemical rate allocation:
- Analysis of synthetic mixtures is needed of the end-member oils.
- The allocation is limited to two or three zones, because there are no representation graphs for more than three mixtures of end-members oils.

2-3-3 Production logging technique:- (in line Spinner flow meter)
Production logging commonly must be applied by production engineers to help in detection the source of reduction in well performance, and give assistance to select and apply the most proper action for improving well productivity (Michael J.economides, 1994).

For example if a commingled well has increasing in water cut , production log can be used to identify the layer or layers which have a major contribution in water cut and specify the proper accomplishment that can be applied, however production logging is not a panacea for well diagnosis and for a reliable application it shouldn`t be run in a vacuum conditions and must be used in combination with well pressure history and flow rate (Michael J.economides, 1994).

Allocating the rate of individual layers can be achieved by running (PLT) to which a number of sensing equipment (pressure, velocity, temperature, and phase holdup) are attached in order to identify layers of poor productivity and non-productive layers. Also, PLT is used to measure the relative participation of each layer in total production. (Reda Rabie, 2010)

Production logging tool is too difficult to run in horizontal or a high deviated well. (Reda Rabie, 2010)

Spinners which are one of the production logging tools are used to measure flow rate both in case running down or up the wellbore. (Ford lane, 2010)
Thermal rate allocation Technique

2-3-3-1 **Description**
The equipment is very small in size and requires an electrical connection to support the required input energy, and it may be used in combination with full-bore flow measurement device, this tool allow generating production profile in one down up hole running either in casing or tubing production, the disadvantage of full-bore flow meter affected by debris appear in the horizontal well therefor ILS may be taken as a back-up flow measuring tool (Ford lane, 2010).

The tool has a very strong shield and the greater efforts of protection must be directed to the moving parts such as the spinner unit, the tool is considered to be practicable in all different orientations. (Ford lane, 2010)

2-3-3-2 **Operating principle**
The moving spinner is connected by reliable roller bearings, and the detection of rotation can be achieved by installing of device called “zero drag hall effect “ which can give a very little threshold and improving the measurement of low flow rates.

In case of high flow rates the device is very reliable due to the roller bearings attached to the assembly, the spinner provide means of measurement of flow rate with orientation information. (Ford lane, 2010)

2-3-3-3 **Selection:**
The selection of the most effective flow-meter will be dependent on a number of parameters such as completion extent, expected phases, production rates, and the presence of debris.

Flow meter with diverter basket provide a specialist role particularly in case of very low flow rate, it can do this by taking a flow from the bottom of the well bore and directed it to a modified ILS. (Production, 2009)
2-3-3-4 Application: (Ford lane, 2010)

1. Generation of production profile through production conduit.
2. Detect tubing leakage.
3. Used as a back-up spinner.
4. Used as logging equipment through preventing sand production tools.

Figure 4: Production Logging Tool (Murat Zeybek 2006)
2-3-3-5 Example of results delivered by PLT:

Figure 5: PLT response (Murat Zeybek 2006)

2-3-3-6 future technique:-

The new technique of the flow scanner tool gives us a new mean in evaluation of PLT technique of rate allocation more than conventional.

This new technique uses spinners and sensors installed across the wellbore diameter provide enhanced data and better interpretation qualities.
Thermal rate allocation Technique

The major advantage of this technology is the ability of measuring the three phases velocity more accurately than conventional technology (Murat Zeybek 2006)

2-3-4 Temperature profile:-

Temperature is a major concern in down-hole specification. Since 1930s temperature measurements have been used by engineers to observe performance of wells on production by: (Brown, 2009)

  1- Determine rate participation.
  3- Evaluating the reliability of fracture jobs.
  4- Identifying the top of cement below casing.
  5- Detect cross flow between layers.

For long period of time the usage of temperature measurements was obfuscated by more effective measurements developed from more advanced logging equipment. However, the progressing of the technique of fiber optic has supported the resuscitation of usage of thermal measurements. (Brown, 2009)

In the 1980s, scientists have developed a method for creating temperature profile along the total depth of producing well using optical fibers; later on in 1990s this technique has been developed to deal with certain petroleum completions. (Brown, 2009)

To collect spatially disseminated temperature data distributed temperature sensing (DTS) doesn’t need movable sections or any electronics being installed into the well bore, but it depends only upon a continuous strand of optical fiber. (Brown, 2009)

A fiber optical distributed temperature sensing system can provide a reliable down-hole temperature values at various periods of time a long wellbore length (approximately every 3.3 ft.) rather than measuring a single value of temperature causatively. (Brown, 2009)
Thermal rate allocation Technique

This uniformity in taking temperature measures give the DTS the advantage of specifying both the time and place of occurring change in values of temperature (Brown, 2009).

2-3-4-1 DTS components:

In classical form it consists of number of major components:– (Brown, 2009)

1. Laser light emitter.
2. Optical disperser.
3. Visualization unit.
4. A unit for treating Optoelectronic signals.
5. Optical fiber strand.

The strand of fiber optic is placed inside a tube for protection, the strand is very thin and has a thickness of 100 microns. And has a core made of silica glass in its center (5–50 microns in diameter), the outer surface of the strand core is coated by silica cladding, to change the cladding refractive index, other materials such as fluorine or germanium are used. (Brown, 2009)

Figure 6: DTS major components. (Brown, 2009)
2-3-4-2 The mechanism:-

The laser source emit tenth light pulses in the strand, each pulse travels down the strand, this light is reflected in the annulus between the core and the cladding By the phenomenon of internal total reflection. (Brown, 2009)

However a portion of the light is nonetheless dispersed as the pulsed moves through the fiber, in DTS applications scattering mode known as Raman scattering is the most important one, which caused by photons inelastic impacts with fiber molecules ,thus the vibrational energy altered. A photon that is scattered can be have one of two actions; either has an increase in energy by travelling the molecule to a lesser state of vibrational energy (anti stokes scattering), or has a decreasing in energy by travelling the molecule to greater state of vibrational energy (stoke scattering). (Brown, 2009)

In Raman scattering the transferred energy between the photon and the molecule depends on the temperature, in Raman scattering there are two components; stokes wave-lengths which is too long wave which is not dependent on temperature, while anti stoke wave-lengths is short wave and very temperature dependent, the ratio of these components proportional directly to the scattering formation temperature. By these definitions we can make a well temperature profile using distributed temperature sensors along the wellbore. (Brown, 2009)
Chapter 3: Methodology:

3-1 introduction:

We present a methodology of allocating gas rate and associated water to each individual layer using temperature measurements and total surface production of gas and water, by driving equations relates the temperature profile and the flow rate.

The cooling effect of the gas is well studied considering Joule–Thomson effect in the wellbore. Synthetic case of a multi zone producing well is used to test the validity of the new developed forward temperature–flow rate model.

We also present a methodology for driving equations of three phases (gas–oil–water) allocating in single layer as well as two layers commingled well.

The developed model is applied to calculate the temperature profile inside the wellbore; the calculated profile is compared with the actual profile. The results show that the new developed model is valid and reliable.
3-2 Well Configuration:
Two layers well producing both water and gas through the same conduit (commingled production). The well is divided into nodes.

Figure 7: well configuration.

3-3 Equations:
The main equations used to apply the developed model are presented in this section. Derivation and further equations are submitted in appendix (B).

A) To get the temperature equation in node 1-2 which describes the two phase flow from drainage radius into wellbore, we assumed that (Reda Rabie, 2010);

1. No heat transfer between the two phases.

2. Each phase move to wellbore in a separate conduit.

3. Conduction heat transfer is taking into account.
4. Work done by the fluid against the viscous force is neglected.

5. Steady State Problem (No energy accumulation in the system).

6. Changes in both P.E. & K.E. are neglected.

7. The medium is homogenous, such that the solid and fluid passing through the pores is evenly distributed throughout the porous medium.

8. The medium is isotropic such that permeability, \( k \) and thermal conductivity do not depend on the direction of the flow.

9. At any point in the porous medium, the solid matrix is in thermal equilibrium with the fluid in the pores.

10. Darcy law applies.

Then the equation becomes as follow:

\[
T_{(r)} = \frac{1}{\beta_{mix}} + \left[ T_e - \left( \frac{1}{\beta_{mix}} \right) \right] \left[ \frac{r}{r_e} \right]
\]

\[
= \frac{q_{w} + q_{g}}{4\pi h} \left( \frac{\rho_{mix} c_{p_{mix}}}{K_{r} \phi} \right) \left( \frac{\rho_{mix} c_{p_{mix}}}{K_{r} \phi} \right) \left( \frac{\beta_{mix}}{K_{r} \phi} \right) \left( \frac{4}{k} \right)
\]

(3.1)

B) The modified equation for two phase flow in the node 2–3 (at which flow stream enters the wellbore) is to be as follows:

\[
T_{3} = T_2 - \mu_{JTM} (P_2 - P_3)
\]

(3.2)

Where \( \mu_{JTM} \) is the Joule Thomson effect for both water and gas phases which can be formulated by applying the mixing rule between water and gas phases as follows:
Thermal rate allocation Technique

\[ \mu_{Jm} = \frac{q_{g1} \mu_{Jg1} + q_{w1} \mu_{Jw1}}{q_{g1} + q_{w1}} \] (3.3)

3-4 Joule Thomson effect:
What is the Joule–Thomson effect? When a non-ideal gas suddenly expands from a high pressure to a low pressure there is often a temperature change. Officially, the ratio of \( \Delta T/\Delta P \) is known as the Joule–Thomson coefficient. (Shoemaker)

Assumptions used to derive above equation of the node 2-3-3’ are as follow:

1) Conduction heat transfer is neglected.

2) Work done by the fluid against the viscous force is neglected.

3) Steady State Problem (No energy accumulation in the system).
Thermal rate allocation Technique

4) Change in P.E. is neglected and also neglect the area change between the two nodes, so change in K.E. is neglected.

5) Compressible fluids.

C) The general energy balance equation which provides the temperature profile between node 3'–6 (vertical section) in which the second zone is included is given by:

\[
T_f = T_{el} + \frac{g \sin \theta}{A} \left( 1 - e^{\frac{z-L}{\alpha z_{L}}} \right) - F_c e^{\frac{z-L}{\alpha z_{L}}} (T_{el} - T_{fbh}) - F_c \left( 1 - e^{\frac{z-L}{\alpha z_{L}}} \right)
\]  

(3.4)

Where:

\( F_c \) is an assumed constant along a certain section \( dz \) of the wellbore and is given for two phase gas–water flow in which the pressure drop due to acceleration assumed equal 30% from the total pressure drop as follow:

\[
F_c = \mu \rho C_v \frac{dp}{dz} - 0.3 \frac{dp}{\rho dz}
\]  

(3.5)

Assumptions used to derive above equation of the node 3'–6 are as follow:

1. Steady State Problem (No energy, mass and momentum accumulation in the system.)

2. Work done by the fluid against the viscous forces is neglected.

3. Constant heat flux forms the tubing to the casing and from the casing to the surroundings at each control volume.

4. Thermal resistance of pipe and steel is neglected compared to that of the fluid in the tubing/casing annulus.

5. Compressible fluid and no area change, so change in K.E. neglected.
3-5 Workflow for estimating gas and water rate per each layer:
The steps for estimating each layer’s contribution in total gas and water production rate (gas and water rate per each layer) are as follow:

1. Obtain data. (Temperature profile, Total production rates, Rock properties, Reservoir properties and well data).

2. Assume initial rate values for both gas and water \( q_g, q_w \) as initial guess depends on layer conditions from its (Permeability, Porosity, Reservoir Pressure, thermal conductivity...)

3. Calculate pressure at different radii and pressure at well head.

4. Estimate Total Pressure drop along the well bore (Cullender and smith).

5. Calculate \((T_f)\) using Joule Thomson effect.

6. Calculate Temperature inside well bore.

7. Compare between measured temperature inside well bore and calculated temperature from the proposed model.

8. If the calculated temperatures match the measured temperature, the assumed gas and water flow rates \( q_g, q_w \) are correct.

9. If the calculated temperatures do not match the measured temperature, then assume new values of \( q_g, q_w \) and return to step 2.

3-6 Sensitivity analysis:

After running our model and obtain flow rates with acceptable errors, sensitivity analysis was made to know which input have the major effects on the accuracy of outputs.
3-7 Proposed equations for three phases flow:

Consider the previous assumptions mentioned for two phases (gas and water) flow, the following equations were proposed for generating a temperature profile in case of three phase production in commingled manner.

\[
T_{(r)} = \frac{1}{\beta_{\text{mix}}} \left[ T_e - \left( \frac{1}{\beta_{\text{mix}}} \right) \frac{4\pi h}{\rho_{\text{mix}} C_{p_{\text{mix}}}} \left( \frac{\rho_{\text{mix}} C_{p_{\text{mix}}}}{K_{\gamma} \phi} \right)^2 \left( \frac{\mu_{\text{mix}}}{k K_{\gamma} \phi c} \right) \right]
\]

(3.6)

The modified equation for two phase flow in the node 2-3 (at which flow stream enters the wellbore) is to be as follows:

\[
T_3 = T_2 - \mu_{\text{JTh}} (P_2 - P_3)
\]

(3.7)

Where \( \mu_{\text{JTh}} \) is the joule Thomson effect for water, gas and oil phases which can be formulated by applying the mixing rule between water and gas phases as follows:

\[
\mu_{\text{mix}} = \frac{\mu_g q_g + \mu_w q_w + \mu_o q_o}{q_g + q_w + q_o}
\]

(3.8)

The general energy balance equation which provides the temperature profile between node 3-6 (vertical section) in which the second zone is included is given by:

\[
T_f = T_e - \frac{g \sin \theta}{A} \left( 1 - e^{-\frac{z-L}{AC_{\text{max}}}} \right) - F_c e^{-\frac{z-L}{AC_{\text{max}}}} (T_e - T_{\beta h}) - F_c \left( 1 - e^{-\frac{z-L}{AC_{\text{max}}}} \right)
\]

(3.9)
Chapter 4: Results and discussion:

According to the following given data from PLT test done in well (X):

1- Gas total production rate.
2- Water total production rate.
3- Rock data.
4- Reservoir data.
5- Well data.
6- Measured temperature profile.
7- Lower zone gas production.
8- Lower zone water production.

We did our calculations and compare the obtained results to the measured data with corresponding errors.

Some of input data were reasonably estimated such as (U, Ke, gas and water thermal expansion coefficient ...), because it wasn’t available.

4-1 Checking validity of equations using One zone two phases:

This model is used to check the validity of getting a temperature profile that can be plotted by applying equations describe temperature as a function of both gas and water flow rates.

By applying the assumptions mentioned in chapter (3) and using the same data but apply it for only one zone and omit the upper zone to simplify the plot.

The results show that these equations can generate a reasonable curve, which means that it can be developed for more than one zone.
Figure 9: temperature profile one zone two phase.
Figure 10: temperature profile and geothermal gradient.
Thermal rate allocation Technique

4-2 Two zones rate allocation:

4-2-1 First iteration results:
Random values are assumed continuously in the lower zone for gas flow rate ($q_{g1}$) and water flow rate ($q_{w1}$) until we get an acceptable temperature profile that is in somehow close to measured temperature profile as shown below.

<table>
<thead>
<tr>
<th>Iteration No. #</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5</td>
<td>5</td>
</tr>
</tbody>
</table>

Table 1: first iteration results.

Figure 11: first iteration.
Thermal rate allocation Technique

4-2-2 Second iteration result:
After getting acceptable temperature profile from the thermal rate allocation model small changes in the values of gas flow rate \( q_{g_1} \) and water flow rate \( q_{w_1} \) is made simultaneously with noticing how close the measured and calculated temperature profiles are:

<table>
<thead>
<tr>
<th>Iteration No.#</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2</td>
<td>6</td>
<td>5</td>
</tr>
</tbody>
</table>

Table 2: second iteration result.

Figure 12: second iteration.
4-2-3 Third iteration results:
The same procedure mentioned above in the second iteration has been
repeated in the third, fourth, fifth, sixth, seventh and eighth iterations until the
best temperature profile is obtained.

<table>
<thead>
<tr>
<th>Iteration No. #</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>6</td>
<td>4</td>
</tr>
</tbody>
</table>

Table 3: third iteration results.

Figure 13: third iteration.
4-2-4 Forth iteration results:

<table>
<thead>
<tr>
<th>Iteration No. #</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>7</td>
<td>4</td>
</tr>
</tbody>
</table>

Table 4: fourth iteration result.

Figure 14: fourth iteration.
Thermal rate allocation Technique

4-2-5 Fifth iteration results:

<table>
<thead>
<tr>
<th>Iteration No. #</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>7</td>
<td>4.5</td>
</tr>
</tbody>
</table>

Table 5: Fifth iteration results.

Figure 15: Fifth iteration.
4-2-6 Sixth iteration results:

<table>
<thead>
<tr>
<th>Iteration No. #</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>7.5</td>
<td>4.5</td>
</tr>
</tbody>
</table>

Table 6: sixth iteration results.

Figure 16: sixth iteration.
4-2-7 Seventh iteration results:

<table>
<thead>
<tr>
<th>Iteration No. #</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7</td>
<td>7.6</td>
<td>4.6</td>
</tr>
</tbody>
</table>

Table 7: Seventh iteration results.

Figure 17: Seventh iteration.
4-2-8 Eighth iteration results:

The following temperature profiles are very close, which means the gas flow rate \( q_{g_1} \) and water flow rate \( q_{w_1} \) corresponding to the thermal rate allocation model profile are taken as calculated model values.

<table>
<thead>
<tr>
<th>Iteration No. #</th>
<th>Gas production rate at lower zone (MMscfd)</th>
<th>Water production rate at lower zone (Mcf/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8</td>
<td>7.65</td>
<td>4.6</td>
</tr>
</tbody>
</table>

Table 8: Eighth iteration results.

Figure 18: eighth iteration.
4-3 KH method calculations:

In case of production from multi-layer reservoir, approximation method depends on the percentage of the capacity of this zone to the total capacity of the reservoir can be used to make roughly estimation of the proportional production of that zone.

\[
\text{Zone production rate} = \frac{(kh)_i}{\sum_{i=1}^{n}(kh)_i} \times (\text{Total production rate}) \tag{4.1}
\]

Using above equation, first estimation can be achieved.

\[
\text{percentage} \% = \frac{(kh)_i}{\sum_{i=1}^{n}(kh)_i} \tag{4.2}
\]

According to data, the percentage

<table>
<thead>
<tr>
<th>Method</th>
<th>Qw1 (Mcfdfs)</th>
<th>Qg1 (MMscfd)</th>
<th>Error% water</th>
<th>Error% gas</th>
</tr>
</thead>
<tbody>
<tr>
<td>KH</td>
<td>4.0013636366</td>
<td>6.9590909099</td>
<td>13.07052713</td>
<td>8.43301435</td>
</tr>
<tr>
<td>TRA</td>
<td>4.6</td>
<td>7.65</td>
<td>0.065174886</td>
<td>0.65789474</td>
</tr>
<tr>
<td>Measured</td>
<td>4.603</td>
<td>7.6</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Table 9: calculated data and corresponding errors.

The calculated values of KH method are moderate and close to the measured values, because there are no significant differences in values of permeability and thickness.

Any small change in the values of permeability and thickness will result in a severely wrong estimation of gas flow rate \( q_g \) and water flow rate \( q_w \).
4-4 Results comparison:
It is very important to know how close your calculated values are to the measured ones and estimating the severity of errors and how acceptable they are.

An effective method for checking how correct your calculated values are; is illustrated bellow, plotting calculated values on the X axis and the measured (real) values in the Y axis.

![Graph](image)

Figure 19: results comparison to measured values.

Thermal rate allocation model calculated values of gas flow rate $(q_g)$ and water flow rate $(q_w)$ are accepted, while values of $(q_g$ and $q_w$) obtained from KH method are showing divergence from the real values.
5-1 Definition:
Sensitivity analysis is the study of how the uncertainty in the output of a mathematical model or system (numerical or otherwise) can be apportioned to different sources of uncertainty in its inputs. (W. Chinneck, 2000)

There are main factors affect temperature distribution down-hole such as (surface temperature, geothermal gradient).

Trials show that the following factors have the major effect on the temperature profile:

1- Reservoir permeability ($k$).
2- Gas formation volume factor ($\beta_{\text{gas}}$).
3- Gas heat capacity ($C_{\text{pg}}$)

We are trying to present the response of changing these parameters, by changing them about ($\pm$20% Error), and then comparing them with original curve values.

Figure 20: reference temperature profile.
5-2 Reservoir permeability ($k = 1 \text{ md}$):

a- First ($k = 0.8 \text{ md}$):

Figure 21: model sensitivity to permeability (1)
b- Second \( k = 1.2 \text{ md} \):

![Graph showing model sensitivity to permeability (2)](image)

Table 10: Response to change in \( k \) values

<table>
<thead>
<tr>
<th>Case 1 ( k = 0.8 )</th>
<th>( k = 1.2 )</th>
</tr>
</thead>
<tbody>
<tr>
<td>( k )</td>
<td>Values</td>
</tr>
<tr>
<td>Qg1</td>
<td>6.5</td>
</tr>
<tr>
<td>Qw1</td>
<td>4.5</td>
</tr>
<tr>
<td>Values</td>
<td>10</td>
</tr>
<tr>
<td>Error%</td>
<td>4.6</td>
</tr>
</tbody>
</table>
5-3 Gas formation volume factor Effect ($\beta_{\text{gas}} = 0.0109$):

a- First ($\beta_{\text{gas}} = 0.00872$)

Figure 23: model sensitivity to gas FVF (1).
Thermal rate allocation Technique

Figure 24: model sensitivity to gas FVF (2).

<table>
<thead>
<tr>
<th>Case2</th>
<th>Bg=0.00872</th>
<th>Bg=0.01308</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Qg1</td>
<td>Qw1</td>
</tr>
<tr>
<td>Values</td>
<td>11</td>
<td>4.61</td>
</tr>
<tr>
<td>Error</td>
<td>43.79085</td>
<td>0.152075</td>
</tr>
</tbody>
</table>

Table 11: response to change in gas FVF Values
5-4 Gas heat capacity Effect ($C_{pg} = 0.485$):

a- First ($C_{pg} = 0.388$)

Figure 25: model sensitivity for Gas heat capacity (1).
b- Second ($C_{pg} = 0.582$):

![Graph showing model sensitivity for Gas heat capacity (2).](image)

Figure 26: model sensitivity for Gas heat capacity (2).

<table>
<thead>
<tr>
<th>Case 3</th>
<th>Cpg=0.388</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Qg1</td>
<td>Qw1</td>
<td></td>
</tr>
<tr>
<td>Values</td>
<td>8.3</td>
<td>5.5</td>
<td>Error</td>
</tr>
<tr>
<td>Error</td>
<td>0.653595</td>
<td>15.27265</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Cpg=0.582</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Values</td>
<td>7.7</td>
<td>3.9</td>
</tr>
</tbody>
</table>

Table 12: Response to change in Cpg values
6-1 Thermal rate allocation technology:

6-1-1 Distributed temperature measurements: (slb)

Distributed temperature sensing (DTS) fiber-optic technology for permanent monitoring can provide temperature measurements over long intervals extending up to the complete length of the wellbore tubing. Optical fiber is light, pliable, and immune, which makes it a cost-effective and flexible. The fiber is integrated in a valuable asset (structure, pipeline, cables, etc.) in a dedicated cable. A single optical fiber can replace thousands of traditional single-point sensors, providing a significant reduction in installation, calibration, and maintenance costs. In addition, assets can now be monitored where previously this was impractical due to their size, complexity, location or environment.

A single permanent down-hole cable enables simultaneous acquisition of distributed temperature measurements through a fiber-optic line. The highly sensitive and accurate data can identify the source of changes in temperature, enabling accurate diagnostics on temperature profile without interrupting production. Interpretation on the temperature profile leads to acceptable estimation of each layer contribution in total flow rate of the different phases.
6-1-2 Configuration of thermal rate allocation system: (omnisens)

I. DTS interrogator unit:

Figure 27: DTS interrogator.(omnisens)

Monitoring distance: > 65 km per sensing channel

II. Long range Distributed temperature Optical Fiber Cable:

Figure 28: Long range distributed temperature optical fiber cable.(omnisens)
Thermal rate allocation Technique

The LTM OFC (long range distributed temperature monitoring optical fiber cable) can accommodate up to 8 fibers. It is a robust cable suitable for direct burial as it integrates rodent protection. The cable includes the optical fibers used for temperature monitoring as well as spare fibers for data communication between the instruments and the control room.

III. Server unit:
Gathers information from single or from multiple TDS interrogator units in a centralized database for storing, data processing and analysis.
6-1-3 Thermal rate allocation integrated monitoring system:

The figure below represent rate allocation integrated monitoring system, the fiber optic in each individual well signals temperature value to interrogator unit which sends the temperature and depth values to the server for analysis and processing. The server generates temperature profile and corresponding calculated values of gas and water flow rates. Each group of wells are monitored by an individual engineer.

Figure 29: Thermal rate allocation integrated monitoring system.
The most suitable available fiber optic cable for wellbore tubing environment is submarine cable.

Figure 30: submarine fiber cable.

Figure 31: fiber optic cable price.
Thermal rate allocation Technique

Taking an intermediate cost for the cable ($1,000/kilometer) an assuming the interrogator unit cost as $1200, the following calculations is made:
For intermediate well depth of 10000 ft (3,050 meters) the cost of one well monitoring system is:

\[ = 1,000 \times 3.05 + 1,200 = \$4,250 \]

Assuming the server cost of $60,000
For a system consisting of (80 wells) the total cost for constructing a thermal rate allocation integrated monitoring system can be assumed as follow:
Total wells installation system = 80 \times 4,250 = \$340,000
Server cost = 80 \times 60,000 = \$60,000
Installations cost = 80 \times 1,000 = \$80,000

Total construction cost = \$480,000

6-3 Thermal rate allocation limitations:

Despite thermal rate allocation method advantages, like many other techniques it has some limitations

1- Sensitive to inaccuracy of the data.
2- In case of failure, a complete pull out of hole is needed.
3- Security is needed for surface facilities (interrogator).

6-4 Limitations of using PLT:
Traditional production-logging methods have limitations in many of today’s wells, wellbore conditions, and fluid types. Wellbore conditions have a large effect on the quality of the data obtained, In vertical wells with high fluid flow rates, the data acquired are accurate and reliable. However, multiphase flow conditions exist in many deviated and horizontal wells. In these wells, conventional production logging tools are often inadequate and may give misleading results.
In the 1990s, the industry began to drill large numbers of deviated and horizontal wells, and so the need to understand and measure fluid flow within complex flow regimes became important as well as development of new tool and techniques (Murat Zeybek 2006).

**PLT has some limitations:** (Muhammad H. Al-Buali, 2011)

1. **Caliper Profile:**
   Limited Caliper Information: Normally, most of the horizontal wells are drilled and logged using logging while drilling (LWD) technology and acoustic calipers are obtained, which have some limitations.
   Well profile after production or stimulation work performed: Once any stimulation work is performed, the wellbore profile is not the same. It is important to consider the original caliper as well as any factors that could affect the well.

2. **Extended Reach Horizontal Wells:**
   The ability to deliver the logging tools all the way to TD is a challenge, especially with extended reach horizontal wells.

3. **Well Production:**
   Normally, the well is logged at a fully and restricted rate, High flow rates affect travelling of the tools.

4. **Dogleg Severity:**
   The maximum rigid tool length depends on the DLS and the borehole size. Auxiliary tools need to be added to provide flexibility between different sections.

**6-4 PLT cost estimation:**

- PLT is always run in a group of tools which feature several tests in one run in hole trip, this is the main economic advantage of the PLT which is less expensive than run each test alone.
- PLT jobs are very expensive, and need high level of experiment and technical ability to be accomplished, considering the additional losses of stopping production, PLT cause the client company significant costs.
Thermal rate allocation Technique

6-4-1 Case study: (Client Company)

Cost estimations for two years (23 jobs):

<table>
<thead>
<tr>
<th>NO.</th>
<th>PROGRAM</th>
<th>ESTIMATED COST (USD)</th>
<th>AFE</th>
<th>COST CENTER</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Production logging (Producers)</td>
<td>13,800,000.00</td>
<td>Production logging</td>
<td>Production Well AFE’s.</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Budgets</td>
<td></td>
</tr>
<tr>
<td>2.</td>
<td>Production logging (Injectors)</td>
<td>160,000.00</td>
<td>Production logging</td>
<td>Production Well AFE’s</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Budgets</td>
<td></td>
</tr>
<tr>
<td>4.</td>
<td>Total Cost estimate for 23 wells</td>
<td>13,960,000.00</td>
<td>Production logging</td>
<td>Production Well AFE’s</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Budgets</td>
<td></td>
</tr>
</tbody>
</table>

Table 13: production logging jobs (23 jobs).

The average cost for the Production logging is \( \frac{13,800,000 + 160,000}{23} \) = \$572,174

From the previous calculation the cost of one well monitoring system is:

\[ 1,000 \times 3.05 + 1,200 = \$4,250 \]

Assuming the server cost of \$30,000

For a system consisting of (23 wells) the total cost for constructing a thermal rate allocation integrated monitoring system can be assumed as follow:

Total wells installation system = 23 \times 4,250 = \$97,750

Server cost = \$30,000

Installations cost = 1,000 \times 23 = \$23,000

Total construction cost = \$150,750

The thermal rate allocation system saves about (13,960,000.00 - 150,750) = \$13,809,250

Without considering lost of production (down time).
Chapter 7: Recommendation and future work:

7-1 Recommendations:

- Rate allocation is essentially important issue for surveillance, controlling and for performing work over and stimulation jobs in commingled wells.

- Thermal rate allocation can be considered as a genetic technique for allocating different flow rates in commingled producing wells due to its accurate results.

- Unlike the PLT which perform a package of measurements, thermal rate allocation technique provides only temperature profile.

- In order to obtain acceptable results from this technique, accurate data must be provided. Model temperature profile sensitivity to some factors is presented in chapter 5.

- This model is applicable for two phases flow, so that the presence of any of the two phases can’t be ignored.

7-2 Future Work:

- Derivation of model equations for more than two zones producing in a commingled manner is required.

- Constructing of model for three phases proposed equations (including oil) is required.

- The explanation of cross flow in this model is not clear so it is required to be included.

- Programing of model equation (software) will be very useful.
Rate Allocation is a very significant issue in commingled production wells observation.

Thermal Rate Allocation is performed through a set of equations that relate fluid flow rate with its temperature.

Accuracy of these equations have been checked through iteration by assuming values of fluid flow rates and then comparing resultant temperature profile with those obtained from PLT.

Results obtained from equations were accurate enough with a very tiny error (0.0652\% for water flow rate & 0.657\% for gas flow rate).

Fiber optic sensors can be installed in the well providing continuous values of temperature and temperature profile which can be used in allocating flow rates in commingled wells.

Fiber optics seems to be economically feasible, technically sounds but also has some limitations.

Although, PLT is more expensive than fiber optics, and don’t provide a continuous monitoring of flow rates, but it provide a very accurate results with a complete package of other values of other important parameters.
## Appendix A: Project Plan Activities:

<table>
<thead>
<tr>
<th>Activity</th>
<th>Allocated Time</th>
<th>Actual Time</th>
<th>Problems</th>
</tr>
</thead>
<tbody>
<tr>
<td>Literature survey</td>
<td>25 days</td>
<td>30 days</td>
<td>Lake of attractive subjects</td>
</tr>
<tr>
<td>Literature review</td>
<td>10 days</td>
<td>7 days</td>
<td>No problems</td>
</tr>
<tr>
<td>Gathering data (GNPOC)</td>
<td>7 days</td>
<td>14 days</td>
<td>Bureaucracy</td>
</tr>
<tr>
<td>Checking validity of data</td>
<td>7 days</td>
<td>9 days</td>
<td>Data not valid for application</td>
</tr>
<tr>
<td>Preparing 1&lt;sup&gt;st&lt;/sup&gt; progressing report</td>
<td>3 days</td>
<td>3 days</td>
<td>No problems</td>
</tr>
<tr>
<td>Gathering data (Petro Energy)</td>
<td>7 days</td>
<td>16 days</td>
<td>Bureaucracy</td>
</tr>
<tr>
<td>Checking validity of data</td>
<td>7 days</td>
<td>4 days</td>
<td>Data not valid for application</td>
</tr>
<tr>
<td>Preparing 2&lt;sup&gt;nd&lt;/sup&gt; progressing report</td>
<td>3 days</td>
<td>3 days</td>
<td>No problems</td>
</tr>
<tr>
<td>Consulting an engineer (Ahmed Fadul)</td>
<td>7 days</td>
<td>7 days</td>
<td>Convincing him with the project validity</td>
</tr>
<tr>
<td>University sudden conflict</td>
<td>3 months</td>
<td>3 months</td>
<td>Work flow stopped</td>
</tr>
<tr>
<td>Consulting an engineer (Mazin Zainelabdien)</td>
<td>7 days</td>
<td>7 days</td>
<td>Our first co supervisor travelled outside the country</td>
</tr>
<tr>
<td>Getting data from Outside</td>
<td>7 days</td>
<td>3 days</td>
<td>No problem</td>
</tr>
<tr>
<td>Second term exams</td>
<td>14 days</td>
<td>14 days</td>
<td>Restricting the work flow</td>
</tr>
<tr>
<td>Data analysis and normalization</td>
<td>2 days</td>
<td>2 days</td>
<td>No problem</td>
</tr>
<tr>
<td>Preparing final form (draft)</td>
<td>7 days</td>
<td>10 days</td>
<td>No problem</td>
</tr>
</tbody>
</table>

Table 14: project plan activities.

**Note:** most of project activities were done simultaneously.
Thermal rate allocation Technique

Appendix B: Equations derivation:-

Attached in CD
Appendix C: Assumptions:

Figure 32: Equations derivation assumption.
Appendix D: Proposed derivation for 3 phases flow rates:

Attached in CD
Thermal rate allocation Technique

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