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Pipeline Modelling for the Lebanese Offshore: Cases in the Oil and Gas Industry

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Abstract

Lebanon must build a pipeline system to carry the hydrocarbons from offshore to the shore. With no available studies and not much experience in this domain, designing a pipeline system in Lebanon is a topic of great concern. In this research, a prototype sample for the Lebanese offshore pipeline system is designed taking into consideration different parameters such as the drainage area, skin factor, Dietz shape, production interval, and the wellhead pressure. The system carries the gas from block 9 offshore Lebanon to a suitable production platform using different simulation software, mainly PROSPER. Different scenarios are modelled where results showed an optimum flow rate of 322.834MMscf/day and a wellbore pressure of 6460.73psi at 3000psi wellhead pressure. Further studies are encouraged to be carried out to transport the hydrocarbons from the wellheads of block 9 to the Zahrani processing plant via specified hydraulics engineering software.

Paper type: Research paper

Keywords: oil and gas, Lebanon, pipeline system, simulation, PROSPER.

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Introduction

The significant natural gas fields discovered over the past decade in the Levant and Cyprus basins have sparked increased interest in the potential oil and gas resources contained in the Eastern Mediterranean Sea. As for Occupied Palestine, several exploration wells were drilled between 1953 and 1957 where oil and gas were discovered. Lebanon re-launched its first licensing round in 2017 to be the latest country to join the race for oil and gas exploration in the Eastern Mediterranean region. The Lebanese Government first estimated the quantities of oil and gas offshore to be 865 million barrels and 96 trillion cubic feet (tcf) respectively, although there was no exploration done yet so the estimations may be not accurate and contain high errors.

A severe fuel/gasoline crisis has hit Lebanon, affecting a variety of sectors, including the humanitarian sector. Several NGOs backed up their activities and operations as the acute fuel crisis worsened, while the needs of all communities grew. Simultaneously, the gasoline crisis that afflicted Lebanon beginning in mid-May 2021 severely limited-service providers' ability to reach out to communities, and hence communities' access to services. Service providers are currently experiencing difficulties because of inadequate internet connections and power outages caused by Lebanon's acute fuel crisis. Due to diminished operating resources and difficulty to access implementation regions, they are encountering many obstacles in maintaining a presence in the field. Service providers are rethinking how they identify, refer, and provide services 00). By producing from its fields, Lebanon will be able to solve a major part of its economical and fuel problems. However, Lebanon needs to establish a pipeline system to transport the oil and gas from the offshore wells to the shore where they will be refined and/or transported to other countries.

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There are no available studies on this topic that is of great concern. A prototype design of the Lebanese offshore pipeline System will be modelled in this study, with a focus on block 9 which is the nearest block from the Palestine Karish field from where the data are correlated. A prototype design of the Lebanese offshore pipeline System will be modelled in this research where data are needed for the Levant basin; for that, a search was done for all the fields in the countries besides Lebanon including Syria, Cyprus, Palestine, and Egypt. The only found data were “AbuMadi Fields” as a condensate reservoir in Egypt and “Karish” gas field in north Palestine which is aside from the Lebanese offshore Block 9. Upon that, data of this study will be correlated from the Karish field for two reasons mainly:

- Karish is so close to the Qana field and is expected to have similar reservoir parameters.
- Lebanon is expected to have a gas reservoir type and not condensate.

Karish data was retrieved from the Energean main website.

This article aims to simulate three scenarios (normal, worst, and best) for the Lebanese block 9 wells. Different software will be used mainly PROSPER, via nodal analyses approach that optimizes the system to produce the needed flow rate most economically, to construct a model with reservoir production variables, and even to develop an equivalent tubing diameter concept (Brown and Lea, (1985); Awal and Lloyd, (2009); Odjugo *et al.*, (2020); Elbrir, (2021)). This article can be prolonged further to study the sub-sea system that will carry the gas from the wellheads to the processing plants passing through the manifolds and production platforms. To model the Lebanese offshore pipeline system, a virtual map should be established showing the location of wells, pipelines, production platform, processing plants, and all the equipment needed for this system. Parameters from this map (mainly pipeline length and water depth) will be inserted into the simulation software to reach the outcomes.

Yikarebogha et al. (2019) conducted a study where variables that affect three gas wells (U300, U400, U500) were analysed, and sensitivity for these variables was carried out. Fancher *et al.* (1963) conducted a field experiment with a 2” pipe size using gas and water as the fluids. The experiment aimed to extend the correlation of Poettmann *et al*. (1952) to accurately predict pressure losses at low flow rates and high GLR’s. Orkiszewski (1967) reviewed all the methods that had been published to that date and then from his observation, prepared a single composite correlation.

1 Material and Methods

A Geographic Information System (GIS) is a computer system for capturing, storing, analyzing, creating maps and displaying data related to the location of the data on the Earth’s surface. GIS can show many kinds of data on one map, such as streets, buildings, pipes, and vegetation that is used in science and almost every industry. This enables people to observe, analyze, and understand patterns and relationships, which leads to the improvement of communication and efficiency as well as better management and decision-making easily. The Lebanese offshore is divided into 10 blocks with different areas **Figure 1**.

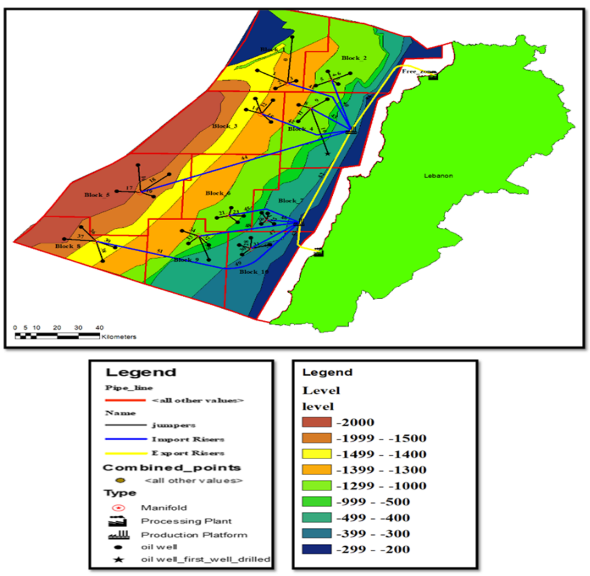

Fig. 1 Lebanese offshore pipeline system virtual map.

1.1 Offshore pipeline system map

A virtual map was created for the Lebanese offshore pipeline system connecting the Lebanese virtual offshore wells to the shore (Fig. 1). This map reveals the oil wells, jumpers, manifolds, import risers, export risers, production platforms, water depth, the first well drilled offshore Lebanon (star symbol in block 4) and the two processing plants in Lebanon that are the Zahrani plant in the south and the Beddawi plant in the north. Gas is being produced from the wells (black points) through the jumpers (black lines) to reach the manifolds (red points) then transported by import risers (blue lines) to reach the production platforms then transported by the export risers (yellow lines) to reach the Beddawi processing plant in the north and Zahrani processing plant in the south. The two-production platform also is connected to permit the ability to transport the produced gas between them and to connect them to another production unit as FSRU if needed. From this map, the followings are to be considered in simulation:

- Platforms will be offshore Lebanon since onshore Lebanon is overcrowded. The location of the platforms should be near the shore because the water depth is shallow and fixed platforms can be installed that are cheaper.

- Two platforms will be enough for the Lebanese offshore that are on 1/3 and 2/3 of Lebanon offshore length since be able to convey the flow to the two different refinery plants of Zahrani and Beddawi.
- Wells are vertical, and their location is arbitrary, taking into consideration that every block should have the manifold that connects the wells in it only.
- If the number of wells is 40, then every manifold will commingle 4 wells and their location is arbitrary.
- If the number of manifolds is 10, then every platform will be connected to 5 manifolds and thus 20 wells.

A prototype for block nine wells will be modelled. The gas will flow from the well bore to the wellhead by the PROSPER software. Block 9 contains four gas production wells. The gas will be transported from the wellheads to the manifold by four jumpers (black pipes number 32, 33, 34, and 35) and then to the production platform by the import riser (blue pipe 48). From the platform, the gas will be transported to the Zahrani plant by the export riser (yellow pipe 53).

1.2 Correlation and estimation

The strength of a relationship between different variables is measured by correlation. Correlations are not used to make predictions; rather, they help to determine the degree to which a pair of variables is linearly related. Correlation analysis is a valuable approach for determining which variables are highly associated with each other. This correlation method seeks to create a line of best fit through the data of variables and reveals how far apart all these data points have deviated from this line to the best fit. The value of the coefficient of correlation will always lie between -1 and +1. When r=+1, it means there is a positive correlation between the variables, if r=-1, there is a negative correlation, and when r=0, there is no relationship0. The Lebanese oil and gas fields are still not maturely explored and only one exploratory well was drilled in block 4 (Fig. 1) on 26th April 2020, and no data was unveiled after drilling. Correlation and estimation of data to be used in the software are always done when designing a prototype sample since some values cannot be obtained before the development and production of the oil and gas field. After production, the real data obtained is inserted into the prototype and real outcomes will be obtained. The data will be correlated from the Karish gas field0 in Occupied Palestine since Karish is the closest field to south Lebanon Block 9. Block 9 and the Karish field will be assumed to be in a homogeneous formation with no barriers, so an evenly distributed flow medium will occur between them, and they will also have the same reservoir characteristics, so the correlation coefficient is equal to one. Data that are not available from the Karish field will be assumed.

1.3 PROSPER software

The PROSPER is a well performance, design, and optimization program that may model most types of well designs prevalent in today's oil and gas sector. Our model was compiled using a well completion of the open hole with no sand control and production tubing of 7-inch nominal diameter (6.184-inch internal diameter). For PVT (Pressure Volume Temperature) the fluid type was “Dry and Wet Gas” and the model was black oil. For IPR (Inflow Performance Relationship) the model used was the Petroleum Experts model 5 (PE 5).

1.4 PROSPER input data assumption and Correlation

All four gas wells in block 9 will be identical and will have the same PROSPER model since the reservoir is assumed to be homogeneous. A summary table for all the PROSPER input data is given in **Table 1**. A three Assumed Variables Sensitivity. Sensitivity for assumed variables was applied to test the percentage of error in the PROSPER model. If an assumed variable has a high sensitivity, it will affect the result significantly if it has any error. Sensitivity will be done for each assumed variable alone. The assumed variables are: Drainage Area; Skin Factor; Diets Shape; Production Interval; Well Head Pressure

Table 1 Summary Table for PROSPER Input Data

PVT		
Parameter	Value	Correlated/Assumed
Gas Gravity	0.612	Correlated
Separator Pressure	2000psi	Assumed
CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
Condensate Gravity	42API	Correlated
WGR (Water to Gas Ratio)	0.004STB/MMscf	Correlated

Water Salinity	27000ppm	Correlated
%H_2S	0%	Correlated
%CO_2	0.076%	Correlated
%N_2	0.627%	Correlated
	IPR	
Reservoir Pressure	7886psi	Correlated
ReservoirTemperature	159F°	Correlated
WGR (Water to Gas Ratio)	0.004STB/MMscf	Correlated
CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
ReservoirPermeability	160md	Correlated
ReservoirThickness	60m	Correlated
Drainage Area	72 acres	Assumed
Dietz Shape Factor	30.9972	Assumed
Wellbore Radius	4 inch	Correlated
Production Interval	20m	Assumed
Time Since Production Started	More than 2 hours	---
ReservoirPorosity	18%	Correlated
Connate Water Saturation	20%	---
Skin Factor	10	Assumed
	VLP	
ReservoirDepth	4337m	Correlated
Deviation	0	---
Tubing Nominal Diameter	7 inch	Correlated
Geothermal Gradient	0.00766F°/ft	---
Overall Heat Transfer Coefficient	8BTU/h/ft2/F°	Correlated
AverageHeatCapacity of Oil	0.53BTU/lb/F°	---
AverageHeatCapacity of Water	1BTU/lb/F°	---
AverageHeatCapacity of Gas	0.51BTU/lb/F°	---
Well Head Pressure	2000psi	Assumed

1.5 The drainage area sensitivity

The drainage area is the area that is affected by the pressure drop created by the well. As the Drainage area increases, the production index (PI) is reduced, so the IPR and VLP will intersect in an operating point with a lower production rate and pressure as shown in **Figure 2**. In this paper, the drainage area is assumed to be 72 acres which is the average. Ten values were modelled to study the sensitivity of the drainage area that is 10, 50, 100, 200, 300, 400, 500, 600, 700, and 800 (Fig. 2), the IPR curves for these values were approximately overlying so the drainage area has a very low sensitivity on the IPR. If the assumption is not precise it will not affect the outcome significantly.

Table 2 Summary table for PROSPER input data,

	PVT	
Parameter	Value	Correlated/Assumed
Gas Gravity	0.612	Correlated
Separator Pressure	2000psi	Assumed
CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
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Water Salinity	27000ppm	Correlated
%H_2S	0%	Correlated
%CO_2	0.076%	Correlated
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	IPR	
Reservoir Pressure	7886psi	Correlated
Reservoir Temperature	159F°	Correlated
WGR (Water to Gas Ratio)	0.004STB/MMscf	Correlated

CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
Reservoir Permeability	160md	Correlated
Reservoir Thickness	60m	Correlated
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Dietz Shape Factor	30.9972	Assumed
Wellbore Radius	4 inch	Correlated
Production Interval	20m	Assumed
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Reservoir Porosity	18%	Correlated
Connate Water Saturation	20%	---
Skin Factor	10	Assumed
	VLP	
Reservoir Depth	4337m	Correlated
Deviation	0	---
Tubing Nominal Diameter	7 inch	Correlated
Geothermal Gradient	0.00766F°/ft	---
Overall Heat Transfer Coefficient	8BTU/h/ft2/F°	Correlated
Average Heat Capacity of Oil	0.53BTU/lb/F°	---
Average Heat Capacity of Water	1BTU/lb/F°	---
Average Heat Capacity of Gas	0.51BTU/lb/F°	---
Well Head Pressure	2000psi	Assumed

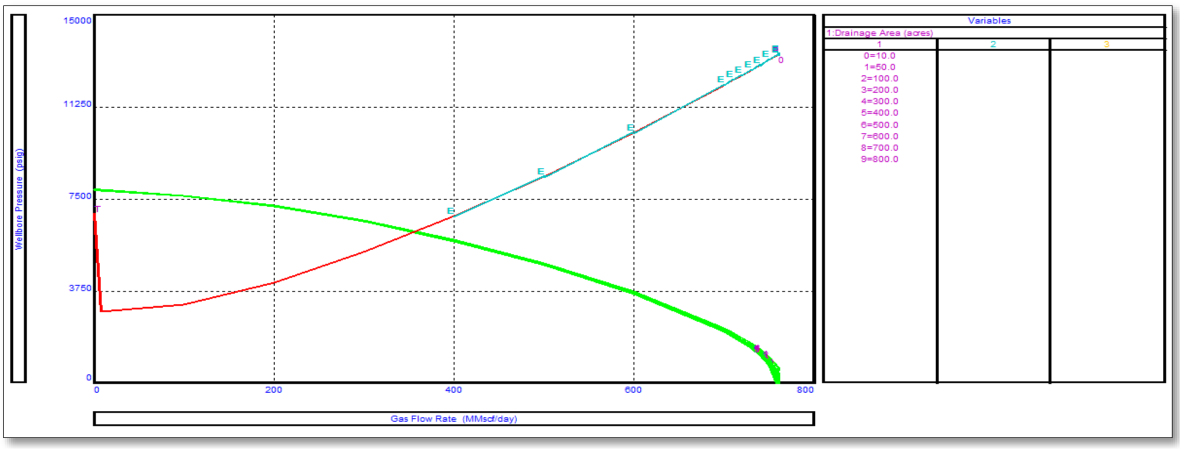

Fig. 2 Drainage Area Sensitivity (IPR=green line, VLP=Blue-Red line).

1.6 The skin factor sensitivity

The skin factor is a parameter that is used to adapt the flow equation calculated from ideal conditions to suit the applications in non-ideal conditions. It is indispensable to predict properly the flow of the hydrocarbons in the reservoir (Xie Yun *et al*., 2010). It is an empirical factor used to account for the combined impacts of many factors that are not considered when the flow equations were derived. Pressure transient test analysis can be used to calculate the skin factor value. A general expression of the skin factor is:

$$S = SD + Sc{+}o + Sp + \sum SPS \quad (1)$$

SD: damaged skin during Drilling, cementing, well completion, fluid injection, and even oil and gas production. Physically, it is caused by external or internal solid particles and fluids clogging the pore space. With well stimulation operations, this component of skin factor can be eradicated or avoided. *Sc+o*: due to partial completion and deviation angle, the *Sc+o* is a skin component that causes the flow pattern near the wellbore to vary from the ideal radial flow pattern. *Sp*: Is obtained because of the non-ideal flow condition surrounding the perforations associated with cased-hole completion. Perforation density, phase angle, perforation depth, diameter, and compacted zone are all factors to consider and affect the rate of inflow into the well (Jansen and Currie, 2004). *SPS*: is obtained due to non–Darcy flow effect, multiphase effect, and flow convergence towards the wellbore0.

For damaged wells' *S*>0, a positive skin factor indicates that the formation near the wellbore is damaged and causes restrictions for fluids to flow between the reservoir and the well. As the skin factor increase, it causes near well pressure drop to increase and reduces the production index so the flow rate decreases (**Figure 3**).

For stimulated wells' $S<0$, a negative skin factor indicates that the near wellbore formation has been stimulated and the contact area between the well and the reservoir is increased. Negative skin is obtained by fracturing or acidizing in the reservoir.
The value of the skin factor varies from about -7 and +100. In this paper, the skin factor is assumed to be 10. In the drainage area, the Skin factor plot Fig. 3, seems to have a moderately low sensitivity to the IPR since the IPR curves are approximately overlying each other with 10 different values of skin factor (0, 2, 4, 6, 8, 10, 12, 14, 16, 18). If our assumption is not precise it will not affect the outcome significantly.

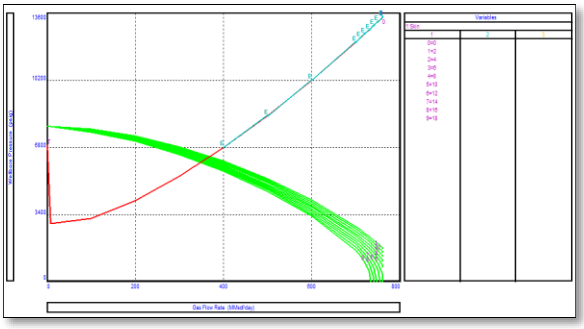

Fig. 3 Skin Factor Sensitivity (IPR=green line, VLP=Blue-Red line).

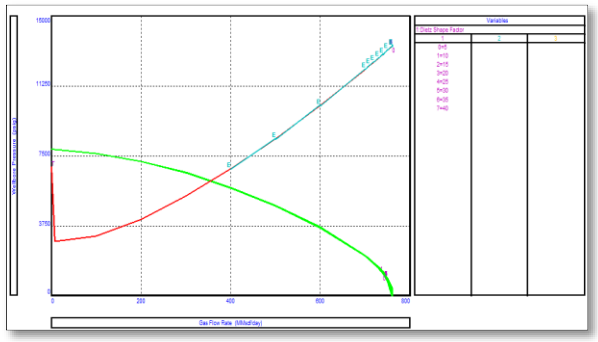

Fig. 4 Dietz Shape Factor Sensitivity (IPR=green line, VLP=Blue-Red line).

1.7 Dietz Shape Factor Sensitivity

The Dietz shape factor describes the geometrical shape of the reservoir and the position of the well in it. Theoretically, as the Dietz shape factor increases the productivity index slightly increases as shown in **Figure 4** so the production rate increases. The maximum value of the Dietz shape factor is about 31 (**Figure 5**) which represents the well positioned in the centre of a perfect circular reservoir. In this research, the Dietz shape is assumed to be 30.99 (Fig. 5). Dietz shape factor seems to have a very low sensitivity on the IPR (overlying curves for 8 different values of Diets shape), so if our assumption is not precise it will not affect outcome significantly. Two figures of the Dietz shape factor values are shown in Fig. 5.

1.8 Production interval sensitivity

It is highly advised for the wells to produce at a suitable flow rate (Li *et al*, 2006a; Song *et al*, 2006). At the beginning of production, a well should be connected to the reservoir formation from where the fluids will flow. Perforation is used to make a channel in the casing pipes and the reservoir formation near the well bore for the fluids to flow. The perforation interval in oil-producing wells should be selected depending on several factors that are mainly the distance from the water aquifer to avoid water coning, and the distance from the gas cap to avoid gas coning, or targeting a specific reservoir layer. The fluid targeted and produced is gas and not oil, so the perforation interval should only be away from the water aquifer to avoid water conning. Water production is harmful to the reservoir since water is much heavier than gas and it needs much energy (pressure) to be produced through the well so the drawdown of the reservoir will be increased.

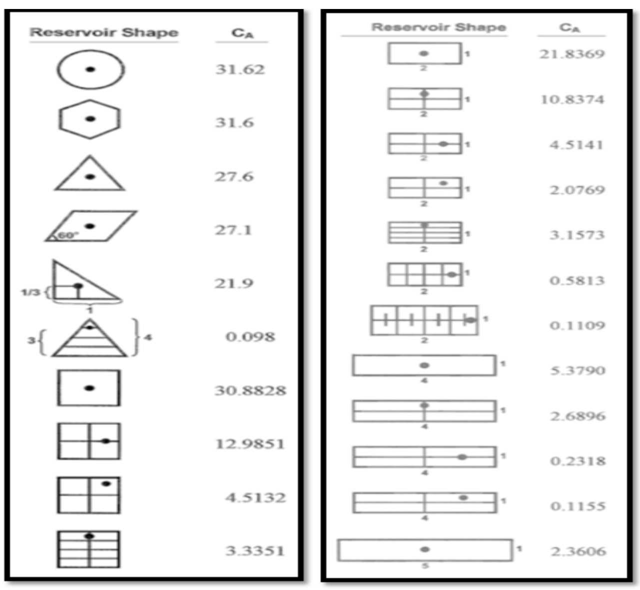

Fig. 5 Dietz Shape Factor values.

As the perforation interval increases, the contact area between the well bore and the reservoir formation is increased which will result in a very high production index increase and so increase the production rate significantly. A perforation interval of 20m is assumed that is above the water aquifer by 40m. seven values of perforation interval were modelled (10, 20, 30, 40, 50, 60, 70) and the resulting curves indicate a big effect of perforation interval on the IPR where the slope of the PI (production index) was changing significantly0. The IPR plot for 60m and 70m perforation intervals are overlying as shown in **Figure 6**. A minimum value of flow rate (300MMscf/day) at 10m of perforation interval and a maximum value (420MMscf/day) at 70m of perforation interval. Perforation interval seems to have a high sensitivity to the IPR, so if our assumption is not precise it will affect the outcome significantly.

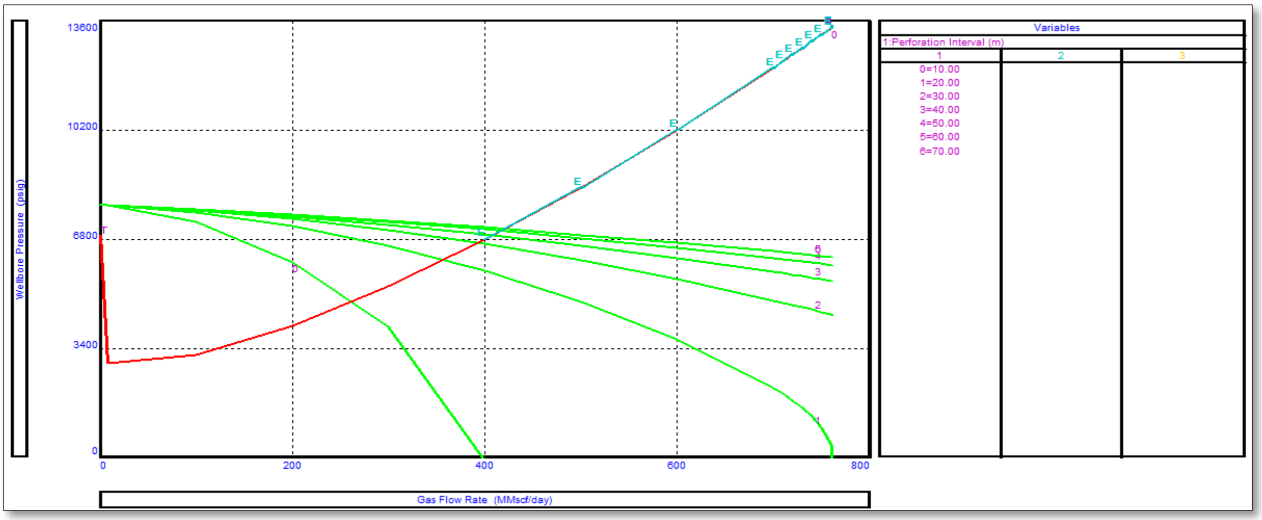

Fig. 6 Perforation Interval Sensitivity (IPR=green line, VLP=Blue-Red line).

1.9 Wellhead pressure sensitivity

The pressure drop through the production pipeline is caused by three types of losses that are friction losses, gravity losses, and minor losses0. Losses due to friction as fluid flow through the production pipe, friction is applied on it from the walls of the pipe. This resistance will result in a pressure drop in the stream. Fluid velocity, pipeline roughness, fluid type, and pipeline diameter affect the friction losses:

a. As the fluid velocity increases, the friction loss increases and may erode the pipeline.
b. As the pipeline roughness increases, the friction loss increases.
c. The fluid type affects the intensity of friction applied by the walls.
d. As the pipeline diameter increases, the friction pressure drops decrease.

The column of fluid in the production tubing will exert pressure on the well bore which is the gravity loss. The pressure of the column is the density of the fluid multiplied by the gravity and the height of the column. The type of fluid (density of fluid) mainly affects gravity loss.

Minor losses are local energy losses caused by the disruption of the flow due to the installation of appurtenances. The type of minor losses are:

a. Loss of energy due to sudden enlargement.
b. Loss of energy due to sudden contraction.
c. Loss of energy at the entrance of the pipe.
d. Loss of energy at the exit from the pipe.
e. Loss of energy in Bends and Pipe Fittings.

For the fluids to flow from the wellbore to the wellhead, the wellhead pressure should be less than the wellbore pressure minus the pressure losses through the production line. Therefore, the wellhead pressure should be optimized to be low enough to keep the differential pressure between the wellbore to the wellhead positive and is limited to a maximum value that above the well will stop producing. The wellhead pressure also has another limitation that is not to be less than the separator pressure plus the loss through the import risers or no flow will be from the wellhead to the separator. The wellhead pressure should be optimized to have a certain pressure (Renpu, 2011).

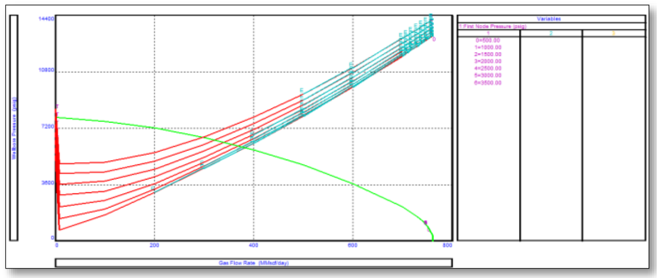

Fig. 7 Well Head Pressure Sensitivity (IPR=green line, VLP=Blue-Red line).

As mentioned above, as the wellhead pressure increases, the VLP shifts upward so the flow rate decreases as shown in (**Figure 7**). Seven values of wellhead pressure starting from 500psi to 3500psi were modelled. A minimum value of flow rate (300MMscf/day) at 3500psi of wellhead pressure and a maximum value (380MMscf/day) at 500psi of wellhead pressure. Wellhead pressure seems to have a high sensitivity on the VLP, so if the assumption is not precise it will affect the outcome significantly.

2 Results and Discussion

2.1 PROSPER Software Outcomes

The outcome of our input data for the PROSPER Software is shown in **Figure 8**. No flow is obtained when the differential pressure between the wellbore and the reservoir (7886 psi) is equal to 0. As the wellbore pressure drops below 7886psi, the differential pressure between the two nodes starts to increase resulting in gas flow from the reservoir to the wellbore. The gas flow rate reaches its maximum value of 761.9MMscf/day at the absolute open flow (AOF), where the wellbore pressure is 0 and the differential pressure between the two nodes is maximum. The IPR curve is not linear due to the compressibility of gas since the pressure is below the bubble point pressure0). The curve is based on 2000psi wellhead pressure and a tubing nominal diameter of 7-inches. The erosional velocity will be reached at a flow rate of 400MMscf/day. The diameter of the tubing should be increased if a flow rate higher than 400MMscf/day is designed, but when increasing the diameter of the pipe the wellbore pressure decreases significantly, as shown in **Figure 9**.

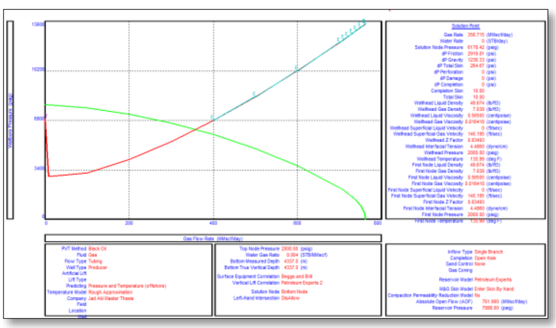

Fig. 8 Operating point within assumed parameters (PROSPER Software) (IPR=green line, VLP=Blue-Red line).

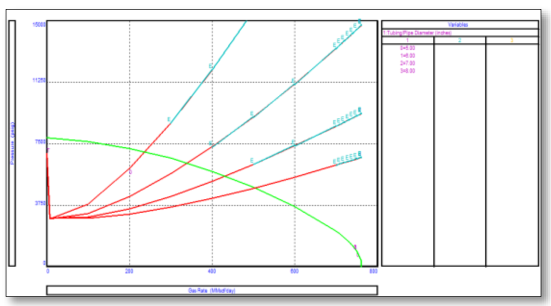

Fig. 9 Tubing internal diameter sensitivity (IPR=green line, VLP=Blue-Red line).

The operating point is the point where the IPR and the VLP curves intersect, and it represents the flowing conditions of the wellbore.

- Wellbore Gas Rate: 356.715 MMscf/day
- Wellbore Pressure: 6178.42psi

All the outcomes of the PROSPER software based on the input data are presented in **Table 3**.

Error! Reference source not found. The wellhead pressure of 2000psi is observed to be able to deliver a high flow rate of 356.715MMscf/day which is not needed. The design was revised, and the wellhead's pressure was increased from 2000psi to 3000psi to obtain better well performance and resulting in reducing the not needed gas flow rate and increasing the wellhead pressure to tackle the high-pressure loss of jumper and import risers. The flow rate was reduced to 322.834MMscf/day when optimizing the wellhead pressure to reach 3000psi as shown in **Figure 10**.

2.2 Scenario best/worst scenario cases for PROSPER modelling

2.2.1 Best case scenario

The best-case scenario for the PROSPER model will be obtained by the maximum flow rate at the operating point on the other hand the best possible flow outcome is given in **Table 3**. This outcome will be obtained by increasing the production index (PI) to the maximum and changing VLP if needed, so they intersect at an operating point with the highest flow rate and pressure possible. To obtain the best-case scenario, all the assumed variables will be modelled to have their best values, except the wellhead pressure which will be fixed at 3000psi to ensure flow from the wellhead to the production platform. Best-case scenario variables values are:

1. The drainage area will be 10 acres which will cause the highest IPR
2. Skin factor will be -5(minimum skin factor that can be imported into PROSPER) which will cause the highest IPR.
3. Dietz shape factor will stay at 31 which will cause the highest IPR
4. Production interval will be 40m to increase the contact area with the reservoir and the wellbore leaving 20m below it to avoid water conning.

2.2.2 Worst-case scenario

The worst-case scenario for the PROSPER model will be obtained by the minimum flow rate at the operating point on the other hand the worst possible flow outcome. This outcome will be obtained by reducing the production index (PI) and changing the VLP if needed so they intersect at an operating point with the lowest flow rate and pressure. To obtain the worst-case scenario, all the assumed variables will be modelled to have their worst values, except the wellhead pressure which will be fixed at 3000psi to ensure flow from the wellhead to the production platform. **Table 4** shows the worst-case scenario parameters:

1. The drainage area will be 800 acres which will result in the lowest IPR
2. Skin factor will be which will result in the lowest IPR
3. Dietz shape factor will be 0.1 which will result in the lowest IPR
4. Production interval will be 10m to decrease the contact area with the reservoir and the wellbore leaving 50m below it to avoid water conning.

Table 3 Best-case scenario parameters.

	PVT:	
Parameter	Value	Correlated/Assumed
Gas Gravity	0.612	Correlated
Separator Pressure	2000psi	Assumed
CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
Condensate Gravity	42API	Correlated
WGR (Water to Gas Ratio)	0.004STB/MMscf	Correlated
Water Salinity	27000ppm	Correlated
%H_2S	0%	Correlated
%CO_2	0.076%	Correlated
%N_2	0.627%	Correlated
	IPR	
Reservoir Pressure	7886psi	Correlated
Reservoir Temperature	159F°	Correlated
WGR (Water to Gas Ratio)	0.004STB/MMscf	Correlated
CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
Reservoir Permeability	160md	Correlated

Reservoir Thickness	60m	Correlated
Drainage Area	10 acres	Best Case Scenario
Dietz Shape Factor	30.9972	Best Case Scenario
Wellbore Radius	4 inch	Correlated
Production Interval	40m	Best Case Scenario
Time Since Production Started	More than 2 hours	---
Reservoir Porosity	18%	Correlated
Connate Water Saturation	20%	---
Skin Factor	-5	Best Case Scenario
	VLP	
Reservoir Depth	4337m	Correlated
Deviation	0	---
Tubing Nominal Diameter	7 inch	Correlated
Geothermal Gradient	0.00766F°/ft	---
Overall Heat Transfer Coefficient	8BTU/h/ft2/F°	Correlated
Average Heat Capacity of Oil	0.53BTU/lb/F°	---
Average Heat Capacity of Water	1BTU/lb/F°	---
Average Heat Capacity of Gas	0.51BTU/lb/F°	---
Well Head Pressure	3000psi	Assumed

Table 4 Worst-case scenario parameters.

	PVT:	
Parameter	Value	Correlated/Assumed
Gas Gravity	0.612	Correlated
Separator Pressure	2000psi	Assumed
CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
Condensate Gravity	42API	Correlated
WGR (Water to Gas Ratio)	0.004STB/MMscf	Correlated
Water Salinity	27000ppm	Correlated
%H_2S	0%	Correlated
%CO_2	0.076%	Correlated
%N_2	0.627%	Correlated
	IPR	
Reservoir Pressure	7886psi	Correlated
Reservoir Temperature	159F°	Correlated
WGR (Water to Gas Ratio)	0.004STB/MMscf	Correlated
CGR (Condensate to Gas Ratio)	9.5STB/MMscf	Correlated
Reservoir Permeability	160md	Correlated
Reservoir Thickness	60m	Correlated
Drainage Area	800 acres	Worst Case Scenario
Dietz Shape Factor	0.1	Worst Case Scenario
Wellbore Radius	4 inch	Correlated
Production Interval	10m	Worst Case Scenario
Time Since Production Started	More than 2 hours	---
Reservoir Porosity	18%	Correlated
Connate Water Saturation	20%	---
Skin Factor	100	Worst Case Scenario
	VLP	
Reservoir Depth	4337m	Correlated
Deviation	0	---
Tubing Nominal Diameter	7 inch	Correlated
Geothermal Gradient	0.00766F°/ft	---
Overall Heat Transfer Coefficient	8BTU/h/ft2/F°	Correlated
Average Heat Capacity of Oil	0.53BTU/lb/F°	---
Average Heat Capacity of Water	1BTU/lb/F°	---
Average Heat Capacity of Gas	0.51BTU/lb/F°	---
Well Head Pressure	3000psi	Assumed

The IPR for the worst-case scenario is shown in **Figure 11**. The production index (PI) has decreased significantly resulting in an absolute open flow of 322.735MMscf/day. The main factor that reduced the production index (PI) is the production interval which has a very high sensitivity. The VLP curve will not be changed. The operating point of the wellbore reached a gas flow rate of 188.416MMscf/day and pressure of 5022.64psi (**Figure 12**). This result is still accepted and the well still can flow under these conditions since the wellhead pressure is 3000psi.

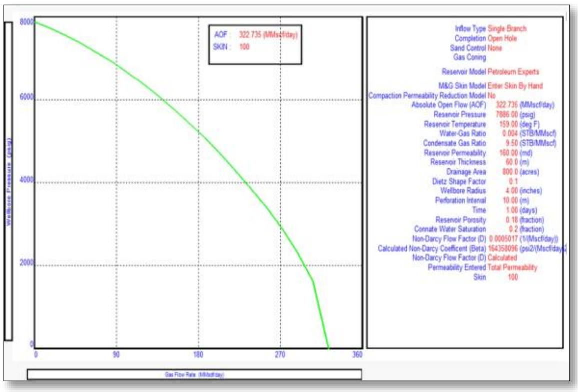

Fig. 11 PROSPER software worst-case scenario IPR.

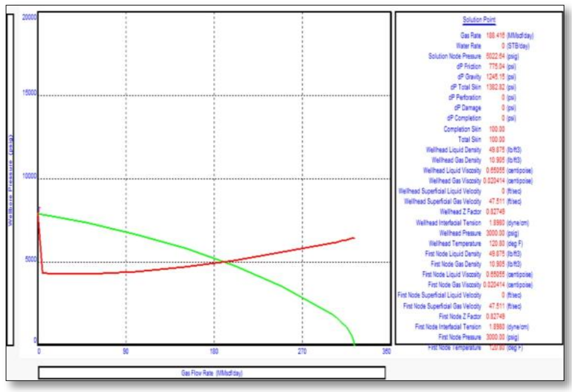

Fig. 12 PROSPER software worst-case scenario outcome (IPR=green line, VLP=Blue-Red line).

2.2.3 Scenarios analysis

Three PROSPER models were carried out in this paper representing the normal case scenario (most likely to happen), best case scenario, and worst-case scenario using three different sets of data. All three sets have common correlated input parameters that are gas gravity, CGR, condensate gravity, WGR, water salinity, %H2S, %CO2, %N2, reservoir pressure, reservoir temperature, reservoir permeability, reservoir thickness, wellbore radius, time since production started, reservoir porosity, connate water saturation, reservoir depth, deviation, tubing nominal diameter, overall heat transfer coefficient, the average heat capacity of oil, the average heat capacity of water, the average heat capacity of gas, and wellhead pressure and also have different assumed input data that are drainage area, Dietz shape factor, and skin factor. The separator pressure does not affect the three models since the surface equipment option is disabled in the VLP section. The normal case scenario has the assumed parameters to be realistic as much as possible as shown in the last sections and the normal case scenario input is shown in Table 1. The best-case scenario was modelled to deliver the best possible wellbore pressure and flow rate and its input is shown in Table 3. The worst-case scenario was modelled to deliver the worst possible wellbore pressure and flow rate and its input is shown in Table 4. **Table 5** shows the outcome for the three PROSPER models**:** All three cases seem to have a reasonable outcome that may occur at any well. The normal case scenario is most likely to happen and is the most realistic case since it relies on logical data. A flow rate of 322.834MMscf/day and a wellbore pressure of 6460.73psi are reasonable and can be optimized easily by modifying the wellhead pressure while production is needed. After obtaining the IPR and VLP curves in the Lebanese block 9 fields, a study should be carried out on the pipeline system to convey the hydrocarbons from the wellheads to the Zahrani processing plant by modelling all the jumper pipes, manifold, import riser, production platform, and the export riser. This study may be executed by using HYSYS or GAP software that is specialized in hydraulics engineering.

Table 5 Outcome for three PROSPER models

Model	Wellbore pressure	Flow rate
Normal Case Scenario	6460.73psi	322.834MMscf/day
Best Case Scenario	7448.43psi	388.725MMscf/day
Worst Case Scenario	5022.62psi	188.416MMscf/day

Conclusions

An economic and fuel crisis started in Lebanon form 2019 and is still ongoing now and one of the solutions to overcome this crisis is for Lebanon to start producing from its fields. However, Lebanon needs to establish a pipeline system to transport the oil and gas from the offshore wells to the shore where they will be refined and/or transported to other countries. Correlation from near fields was necessary since no data is available from the Lebanese fields. The best field to match the Lebanese block 9 was the Karish field located in northern Palestine. Three scenarios were carried out using the PROSPER software that is the normal, best-, and worst-case scenario. The normal case scenario had all the assumed parameters set to be in their real or most probably values, the best case in the highest productivity index and the worst case resulting in the lowest one. Some petrophysical parameters in common such as gas gravity, water salinity and others were taken into consideration whereas other different ones such as the drainage area, Dietz shape factor, skin factor, perforation interval, and the wellhead pressure were assumed. The outcomes of the different scenarios were reasonable from the productivity point of view and equal to 188 MMscf/day, 322MMscf/day and 388 MMscf/day for the worst-case, the normal case and the best-case scenarios, respectively. After obtaining the IPR and VLP in the Lebanese block 9 wells, a further study would be done for the pipeline system from the wellheads to the Zahrani processing plant by modelling all the jumper pipes, manifold, import riser, production platform, and the export riser. This advanced study should be done by using software specialized in pipeline engineerings such as HYSYS or GAP simulation software.

Nomenclatures

AOF	=Absolute Open Flow	[-]
API	=American Petroleum Institute	[-]
Btu/r	=British Thermal Unit Per Hour	[J]
Btu/mole	=British Thermal Unit Per Mole	[J/mole]
GOR	=Gas to Oil Ratio	[-]
IPR	=Inflow Performance Relationship	[-]
md	=Millidarcy	[s/m]
MMscf/day	=Million Standard Cubic Feet Per Day	[-]
Pe	=External Boundary Radius Pressure	[-]
Ppm	=Parts Per Million	[-]
Pwf	=Well Sand-Face Mid-Perf Pressure	[Pa]
Sp	=Gravity: Specific Gravity	[-]
STB/day	=Standard Barrel Per Day	[m^3/day]
STB/MMscf	=Standard Barrel Per Million Standard Cubic meter	[-]
Tcf	=Trillion Cubic Feet	[m^3]
VLP	=Vertical Lift Performance	[-]

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