1. Introduction

Asphaltene flow assurance is a critical subject during oil production and transportation in the upstream oil industry. Solid asphaltenes are precipitated and grown into aggregates that plug the pore throat of a rock formation, production tubing, surface flowlines and/or further downstream. These organic types of flow restriction are used to cause formation damage or production loss which require costly remedial measures. When the problem area is a reservoir rock surface, the issue is not only one of simple flow restriction but also of ultimate oil recovery deterioration owing to wettability alteration. Furthermore, solid asphaltene particles as nuclei can assist in forming tight emulsions that reduce oil-water separation efficiency and oil quality from the perspective of water content. The accumulation of asphaltene deposits in the surface oil-water separator is another factor that reduces separation efficiency because of periodic shut-down to remove sludge. Chemical treatment and/or facility design modification can be applied to mitigate such issues. Gas injection is a promising technique of enhanced oil recovery (EOR) that changes the composition of reservoir fluid by mixing with injection gas, which can enhance asphaltene precipitation. The risks associated with asphaltene precipitation must therefore be carefully evaluated as a part of potential gas injection application. Indeed, the increase of asphaltene risks related to gas injection is widely recognized.1)–11)

Because of its importance in securing asphaltene flow assurance, the author and associated research teams have conducted various asphaltene analyses. This work consistently requires some novel contrivance to understand the underlying mechanics of asphaltene behavior whereas apparent contradictions are often encountered. For example, the asphaltene onset pressure (AOP) is detectable at some locations but not others,12)–15) and some asphaltene deposits observed in the field have not been detected from experimental predictions. This article is therefore motivated by the need to summarize the practical lessons learned with regards to asphaltene issues in industry.
2. Materials and Methods

2.1. Reservoir Fluid and Asphaltene

Although asphaltene precipitation is theoretically considered a reversible process, the onsite reality is often different. Single-phase bottomhole samples were used in all case studies to ensure preservation of the original fluid information. The characteristics of the reservoir fluid and asphaltene are summarized in Table 1.

2.2. Experiments

AOP is a fundamental characteristic that represents the wellbore and near-wellbore asphaltene behavior. All evaluations were conducted on the basis of laboratory-measured AOP data derived from a single-phase fluid sample. The measured AOP as key experimental data are used for model calibration. Samples were measured using the filtration method and laser light-scattering technique. The classical filtration method uses 0.5-μm filter and single-phase bottomhole samples. At least two measurement series were performed at each fixed temperature: according to a rule of thumb, a typical setting assumes reservoir temperature and another represents the wellhead or surface facility operating temperature. In a measurement series, a subsample of homogenized fluid is stabilized to pass through the filter at a certain pressure, and then flashed to measure the asphaltene contents. If the stabilized pressure is below AOP, the asphaltene concentration in the flashed sample should...
be less than the original because of precipitated asphaltene particles trapped by the filter. LST is the latest technique that is more convenient and more widely applied for isothermal depressurization, in which laser light transmittance is continuously monitored to detect a reduction, which represents AOP and is caused by obstruction of asphaltene solid particles. This method has recently been applied in parallel with high-pressure microscopy (HPM) to more accurately detect AOP. Thus, in laboratories where both HPM and LST are available, both approaches have been taken for cross-checking purposes.

2.3. Numerical Modeling

Numerical simulations were designed using the commercially available software Multiflash®. The cubic plus association (CPA) method was applied, which involves the Soave-Redlich-Kwong (SRK) cubic equation of state (EoS) for fluid characterization with additional terms incorporated into the models for asphaltene characterization. Software version-3.6 was used for the case studies-1 to 3 and version-4.1 for the case study-4. The overall study workflow, covering the case studies 1-4, is summarized in Fig. 1. Baseline models were generated on the basis of model input data in Table 1. AOP is crucial for validating the numerical models and acquired by the applicable methods mentioned in the previous section. The calibrated models were used for subsequent sensitivity analyses.

3. Risks in Gas Injection

3.1. Case Study-1: Impact of Injection Gas Types

A giant offshore field has long faced the asphaltene problem in production tubing that has not undergone remediation. Such asphaltene deposits have been handled using mechanical, chemical, and/or operational approaches, such as the use of a gauge cutter to drift tubing, xylene soaking, drawdown reduction by a horizontal well, and pressure maintenance by gas and water injection. The downhole asphaltene inhibitor squeezing technique was also used to delay asphaltene deposition in tubing and extend the interval between subsequent asphaltene removal operations. However, the result of squeezing treatment was insufficient owing to the short inhibitor retention time on the reservoir rock surface. The more conventional continuous downhole inhibitor injection method was not considered a viable option for economic reasons because large investments were required to introduce chemical injection lines newly into dual-completed wells. This problematic asphaltene field had historically used lean gas injection without any observation of further asphaltene deposition. A new gas injection EOR plan was developed to increase oil recovery and a case study was therefore performed by focusing on a preparatory evaluation of asphaltene-precipitation behavior under gas mixing conditions to identify and eliminate risks associated with the gas injection plan.

AOPs were measured from the single-phase bottomhole sample of Well-A under two conditions assuming both natural depletion and gas injection. A baseline numerical model was first generated, calibrated to the natural depletion AOP, and fine-tuned to adjust for anomalously light hydrocarbon (C1) content to the average reservoir value by proportionally recalculating the contents of the remaining composition. The model provides the baseline APE and subsequent sensitivity analysis was performed assuming three types of potential injection gases with compositions of: (1) natural gas with the highest C1 content; (2) associated gas with the
highest C2+ contents (i.e., richest); and (3) a mixture with intermediate characteristics between those of natural and associated gases (Fig. 2). The model validity was checked by comparing APEs, assuming the gas-mixed cases, with experimental AOPs derived from gas titration tests.

In the case study, the asphaltene precipitation risk evaluation focused on a certain section of the entire flow stream from reservoir to surface facilities. The focused-section was a wellhead and manifold line at the topside facilities on offshore platforms mostly because of the limited potential of counter mitigation for post injection. The risk impact was evaluated on the basis of APE expansion magnitude and the relative relationship between operating conditions and all APEs on thermodynamic plots (Fig. 3). The associated gas (the wettest gas with lowest C1: 40 mol%) was considered more risky than other gases because the lower APE boundary approached closer to the operating conditions upon mixing with more gas, and half of the operating condition was ultimately covered within the expanded APE. However, these risks could be mitigated by a full-field development plan (FFDP) that will move the operating conditions away from APEs. Conversely, the natural gas (the driest gas with highest C1: 85 mol%) showed a unique trend that deviated the lower APE boundary away from the operating conditions because the APE expansion could be offset by moving the saturation pressure line to higher levels. This offset decreased the asphaltene precipitation risk by adding natural gas. The mixed gas revealed an intermediate behavior of the associate and natural gases. The APE expanded upon shifting the saturation pressure line upward with increasing mixed gas. The offset was well balanced to maintain the lower APE boundary at the original position.

Risks along other sections, such as the in-situ reservoir and tubing, also depended on injection gas type with the highest risk posed by natural gas. However, asphaltene-induced formation damage was considered unsevere or at an undetectable level because there was no operational report for deterioration of gas injectivity and/or permeability during previous activities of actual natural gas injection (1988-2000). Through all the analyses, little risk was observed at the surface facilities except for the associated gas. Even for the associated gas, the implementation of an FFDP was expected to lower the wellhead flowing pressure and secure operational robustness from a risk management viewpoint. A back-up option was discussed in case asphaltene precipitation was not effectively remediated at upstream locations prior to the surface facility (i.e., in the tubing and reservoir). In this worst-case scenario, asphaltene solid particles deposited upstream might flow into the surface facilities and cause problems. Preparation of adequate space was therefore recommended for immediate installation of a chemical injection pump as a remedy action. For practical purposes, the capability and feasibility of chemical injection pump installation
and adequate electrical supply should be checked.

3.2. Case Study-2: Concept of Pseudo APE

The subject field in the case study-1 consists of two main producing reservoirs: an asphaltene problem has been caused in the upper reservoir whereas no issues in the lower reservoir. The risk evaluation in case study-1 therefore primarily focused on the upper reservoir. However, the gas injection EOR plan included the lower reservoir as a target. Here, to evaluate the lower reservoir that has no history of asphaltene precipitation, a problem rises for numerical modeling because no baseline APE can be generated on the assumption of natural depletion. This is because the standard measurement, typically obtained from isothermal depressurizing test using LST, cannot detect any AOP for the lower reservoir fluid under the operating conditions without gas injection. This finding is consistent with the operational history in the lower reservoir. To generate a baseline APE for the lower reservoir fluid under no-gas-injection conditions, an estimated AOP must therefore be assigned for model calibration by any means.

Deliverables from the gas titration evaluation were first used to estimate the AOP. Figure 4 shows typical examples of the gas titration results for two reservoirs, and AOPs were detected under gas-added conditions at several temperatures. Pairs or series of AOPs at each temperature are plotted on certain linear regression trends, which extend to the y-axis at conditions of 0 mol% injection gas. These intercepts are recognized as AOPs at the no-gas-injection conditions. Four y-intercepts of the upper reservoir fluid exist below the saturation pressure at 62-200 °F. This approach is realistic because actual AOPs obtained from the LST method must be above the saturation pressure. However, all y-intercepts of the lower reservoir fluid exist below the saturation pressure at 62-245 °F, which means that these y-intercepts are unrealistic AOPs.

The case study-2 involves interpretation of all findings delivered from the AOP measurement tests using LST. Even the absence of AOP detection during isothermal depressurization scanning processes is still meaningful. The absence of AOP detection can be interpreted that the APE does not intersect the scanning pressure range. As one of the possible scenarios shown in Fig. 5, a pseudo APE must exist at the lower temperature side of the #1 isothermal depressurization scanning range so that the APE does not overlap any of the scanning pressure lines (i.e., temperatures of 64, 100, 150, 200, and 245 °F). This pseudo APE position might be conservative and has further potential to be smaller and/or shift away from the #1 scanning pressure.
3.3. Case Study-3: Vaporizing Gas Drive

In this case, the subject field has more than 45 years of production history with maintaining reservoir pressure powered by water injection followed by crestal gas injection\(^\text{13}\). To recover further oil, a new gas injection pilot (GIP) project was performed at a sector of the flank area in the field. The well location and time-lapse gas flooded-out cross section images are shown in Fig. 6. In October 2007, the first asphaltene deposits were observed in Well-D located 1.5 km south of the injector Well-E. An immediate remedial response was taken in 2008 to deal with the first field observations of asphaltene deposition. To evaluate details of asphaltene behavior in the GIP area, single-phase bottomhole samples were collected from Well-F for study because of their relevance from the aspect of being the most recent and close sampling location to the GIP area with no contamination with injection gas. A series of isothermal depressurizing tests detected a unique AOP for a mixture of the reservoir fluid and 50 mol% injection gas, whereas no AOPs were detected for other mixtures with lesser amounts of gas (0-43.75 mol%). A numerical fluid model was subsequently generated on the basis of the experimental data by Yonebayashi et al.\(^\text{13}\) to estimate APE.

As shown in Fig. 6a), the baseline numerical model was initially generated with AOP calibration for the mixture of Well-F fluid and 50 mol% injection gas. Based on the modified concept of pseudo APE extensively applied for mixed fluids, possible APEs were also developed for other mixtures by adjusting the injection gas concentration of the baseline model to 0, 25, 38, and 44 mol%. A series of AOP-calibrated and pseudo APEs mimicking the continuous gas injection process were not located on the tubing P-T plots. This was in contradiction to the actual asphaltene deposit observa-

![Diagram](image_url)

**Fig. 6** Estimation of Gas Sweep Area Progress for Validation of VGD-affected APE Shifting Area
tion from Well-D. Further study was therefore motivated to resolve this contradiction by incorporating more practical fluid dynamics into the APE investigation.

The minimum miscibility pressure (MMP) derived from the slim tube tests using Well-F fluid was close to the reservoir pressure but lower than the injection pressure. Under these conditions, the expected driving processes depend on reservoir location: a miscible drive possibly near the injector followed by an immiscible drive away from the injector. In the miscible process, first-contact miscibility can be achieved at a closer location such as near the wellbore. However, multi-contact miscibility can be expected by vaporizing gas drive (VGD) even away from the injector location. The injection gas is enriched as it makes contact with intermediate mass hydrocarbons of the reservoir oil. This enrichment assists with reaching miscible conditions as illustrated in Fig. 7. Injection gas and reservoir Oil-F are not miscible under the initial conditions; therefore, the injection gas initially displaces oil immiscibly away from the injection well but leaves some of the oil behind the gas front.

The VGD process supposes the first contact to generate an overall composition $M_1$ on the basis of relative proportions of injection gas and nondisplaced oil. Two components of liquid $L_1$ and gas $G_1$, on the tie line passing through $M_1$ are in equilibrium at point $M_1$. In the subsequent second contact process, further gas injection pushes the equilibrium gas $G_1$ to contact fresh reservoir oil and liquid $L_1$ is left behind as residual saturation. The second contact generates a new overall composition $M_2$ with corresponding equilibrium gas $G_2$ and liquid $L_2$. Further injection makes $G_2$ flow ahead to contact fresh reservoir oil. The process repeats at the displacing front and results in steady alteration of the gas composition. When reaching the plait point composition, multi-contact miscibility can be generated. From the view point of common AOP measurement experiments for evaluating gas injection risks, the mixture compositions assumed in the experiments (Well-F reservoir fluid and 0-50 mol% injection gas in the case study) can be positioned on the unique line between Reservoir Oil-F and injection gas. However, the reality should cover the subsequently altered compositions in the VGD process, which can be located on the lines between Reservoir Oil-F and $G_1, G_2, G_3, ..., G_n$. Otherwise, the study can overlook a true risk.

To more fully account for the VGD process, the case study-3 assumed a series of three enriched injection gas compositions that covered the continuous enrichment process. The intermediate hydrocarbons (C3-C6) in the original injection gas were assumed to increase gradually by maintaining similar compositional proportions of reservoir fluid, followed by normalizing other components (Fig. 8). On the basis of the baseline numerical model, three enriched gases were examined as to how they affected the APE. As enriched gas increases to mix with the reservoir fluid, the APE expands downward (i.e., to the side of lower pressure) (Fig. 6b)). As a result, the trajectory of expanded APEs can include the bottomhole conditions of the tubing P-T line.

![Fig. 7 Schematic of Vaporizing Gas Drive (VGD) Process](image)

![Fig. 8 Assumption of Enriched Gas Compositions for Case Study-3](image)
This is consistent with the actual observations of asphaltene deposition in the GIP area. This situation can provide a hypothesis for which asphaltene precipitation is observed during a limited period when enriched compositions reach the production wells. Preparation of counter remedies at the time of gas break-through is therefore recommended.

The trajectory of VGD-incorporated APEs are compared with production monitoring results and reservoir flow simulations to investigate the validity and consistency with periodical gas sweep progress, as shown in Fig. 6c). The cross section in the GIP area consists of four wells: Wells-G and D as producer and observation well in ascending order from injector Well-E. The first asphaltene deposit was observed at Well-D in 2007 at the same time as gas break-through. The coincident timing of two events verifies the hypothesis that the accumulation of enriched gas might cause asphaltene deposits around Well-D. Another coincident occurrence of gas break-through and asphaltene deposits was observed in the OBS well in 2008. The sequential history of Well-G was recalled as further evidence. The first gas break-through was observed in 2005; however, no asphaltene issue was reported from this well in 2008. After 3 years since the first gas-breakthrough, the injection gas accumulated around Well-G was considered to have returned to the original injection gas composition. The findings in the three wells (D, G, and OBS) can be explained by either expansion or shrinkage of the APE trajectory area in the fluid dynamics, such as the VGD process. The common evaluation without consideration of VGD simply assessed static asphaltene behavior. However, the importance of dynamic asphaltene behavior should be considered in which the precipitation risk varies in the continuous gas injection displacement process, with a maximum near the gas front and decreasing as the gas is swept out.

4. Location-dependent Risks: Geochemical Insights

The case study-4 involves uneven asphaltene precipitation risk distributions in a unique field that applies a produced-gas reinjection (PGRI) scheme\textsuperscript{14),15). A comprehensive study was performed during the development phase by linking the asphaltene experimental data with the geo-history information from the field. The experimental evidence from the fluid analysis (i.e., regular asphaltene flow assurance measurement of AOP) was difficult to reconcile because some samples yielded AOPs but others did not. To better understand the discrepancy, two common insights were identified from engineers: (1) compositional gradients owing to large structural depth variation and (2) a difference of sampling horizons consisting of three main production zones. However, correlations were not found out between the anomalous experimental results and insights. To truly understand the underlying phenomenon, a multidisciplinary discussion involving engineers and geoscientists was required. In general, geoscience deals with immovable hydrocarbons (e.g., bitumen) from an oil-in-place evaluation perspective, whereas the engineers focus on the asphaltene issue. The elements are handled by either discipline differently; however, the essence is two sides of the same coin because solid bitumen is a result of asphaltene precipitation from a liquid phase. An analogue field was considered for which a hypothesis of oil migration history was proposed, resulting in an uneven solid bitumen distribution in the field. The linkage between solid bitumen and asphaltene in a reservoir fluid is that solid bitumen commonly exists in the analogue field whereas the asphaltene content is particularly low.

These two factors were considered to be linked to the hydrocarbon migration history, entrapment, and leakage. Several geoscience modeling studies\textsuperscript{54)~57) proposed a hypothesis of at least two-stage hydrocarbon migration to form solid bitumen. The hypothesis, supported by a fluid inclusion study\textsuperscript{58), assumed sequential events such as (1) an initial charge with asphaltene-bearing oil around 200-165 Ma, (2) followed by seal failure that resulted in reservoir pressure decline with brine re-saturation around 165-125 Ma, and then (3) seal re-establishment allowed a secondary hydrocarbon charge around 125 Ma. The solid bitumen deposition might be caused during the pressure decline stage at the timing of seal failure. A further bitumen study to investigate its stratigraphy and/or location-dependent distribution features\textsuperscript{59) showed that the most abundant solid bitumen was located in the highly fractured rim area in the shallowest region and less in the platform interior. The different occurrence was possibly caused by geological heterogeneity in which the seal failure responded variably with pressure, such as more rapid pressure reduction in the highly connective fractured area and a slower pressure reduction in the lower permeability matrix. A rapid pressure reduction could enhance bitumen stabilization compared with gentle propagation. Aside from the pressure reduction, another trigger for stabilizing solid bitumen is possibly a change of oil composition during hydrocarbon migration. Following a charge modeling study\textsuperscript{60) and asphaltene studies\textsuperscript{61),62), the charging history determines hydrocarbon distribution by fluid mixing over a geological time scale such as initially low maturity oil migration followed by high maturity oil. This mechanism was considered as an alternative scenario to form an uneven distribution of solid bitumen. Higher hydrocarbon contents could charge along the enhanced flow pathway such in as the high connective fractured area; therefore, this biased flow might form the uneven bitumen distribution.
The same hypotheses were applied to our subject field where both oil charging scenarios were possible. Schematic diagrams of both mechanisms are shown in Fig. 9. The total-organic-carbon (TOC) data was checked to investigate the regularity of spatial bitumen distribution (Fig. 10). Three regularities are observed from macro- to small-scopic viewpoints including field-wide, local area-wide, and well-location perspectives. Higher bitumen deposition is observed as moving from west to east on a field-wide trend, from the low permeable matrix (i.e., platform interior) to the high permeable fractured area (i.e., rim) on a local area-wide trend, and from the lower to upper horizons in same well-location. The bitumen deposition process is technically synonymous with de-asphalting. A higher bitumen occurrence can therefore be interpreted to a lower asphaltene concentration remaining in the liquid oil and consequently higher asphaltene as moving from east to west, from the rim to the platform interior, and from the upper to lower horizons. Based on the interpreted results, ratings of the asphaltene precipitation risk were assigned by location as shown in a matrix chart (Fig. 11). To reproduce the clearness of the TOC variation trends by location, a different magnitude is assigned to the risk ratings in each dimension. For example, risk ratings on the small-scale vertical spatial position at the same well location are set to intermediate magnitudes between horizons I to III within 6 rating variation. Risk ratings applied to the medium-scale spatial position are set to large magnitudes between horizontal areal locations for the platform interior versus rim within 16 rating variation of the identical horizon (ex. horizon-I in platform interior versus horizon-I in rim, and same way for horizons-II and III). Finally, the smallest risk rating magnitude is set to the largest-scale spatial position within 1 rating variation between west versus east in west, from the rim to the platform interior, and from the upper to lower horizons. Based on the interpreted results, ratings of the asphaltene precipitation risk were assigned by location as shown in a matrix chart (Fig. 11). To reproduce the clearness of the TOC variation trends by location, a different magnitude is assigned to the risk ratings in each dimension. For example, risk ratings on the small-scale vertical spatial position at the same well location are set to intermediate magnitudes between horizons I to III within 6 rating variation. Risk ratings applied to the medium-scale spatial position are set to large magnitudes between horizontal areal locations for the platform interior versus rim within 16 rating variation of the identical horizon (ex. horizon-I in platform interior versus horizon-I in rim, and same way for horizons-II and III). Finally, the smallest risk rating magnitude is set to the largest-scale spatial position within 1 rating variation between west versus east in
cases of the same local location and horizon. The highest temperature data for detecting AOP is filled in the corresponding cells. Some fine tunings were applied to incorporate geological heterogeneity, such as uncertain location-classification owing to sparse data, into the fluid sampling location cells on the matrix chart. For example, the Well-J was sampled from the platform interior location according to the gross geological definition; however, a post-analysis incorporating geological heterogeneity into fine classification revealed transition-zone-like features. Thus, the Well-J was re-assigned in the group of transition zone. Re-adjustment can be continued as needed whenever new data are collected until a sufficiently dense dataset is accumulated. As a result, two thresholds for AOP detection separated by temperature conditions are obtained from the matrix chart. Threshold ratings between 14 and 17 detect AOP at or below the reservoir temperature. Threshold ratings between 9 and 13 are split between whether AOP is detected or not.

Variation in the magnitude of asphaltene instability was evaluated by numerical models reproducing the asphaltene precipitation behavior of Wells-H and J fluids. The former represented the platform interior with a higher risk rating of 18, whereas the latter was at the transition-zone-like location with a lower risk rating of 14. Once the baseline models calibrated with experimentally measured AOPs were established for each fluid, the sensitivity was studied as a function of asphaltene content. The variation in asphaltene content was determined by considering the available data between the transition zone (0.22 wt% in Well-J fluid) and platform interior (0.48-0.64 wt% in Well-H fluid). The ratio of 1 : 3 was calculated using the maximum and minimum values of 0.64 wt% and 0.22 wt%. The upper range in sensitivity analysis therefore correspond-
ed to 3.0 times while the lower range was set as 0.2 times that covered a reciprocal of 1 : 3. Figure 12 shows the impact of asphaltene content on the APE for each fluid model. The baseline APEs have common characteristics such as similar shapes and sizes except for their locations on the P-T diagram. The location differences capture the variation of asphaltene precipitation risk ratings between both fluids. The Well-J model (i.e., lower risk rating of 14) locates the baseline APE at a lower temperature compared with the Well-H model (i.e., higher risk rating of 18). As a sensitivity response to increased asphaltene contents for the Well-J model, the APE boundary shifts to the higher temperature side to allow intersection with the isothermal line at 100 °C. A comparison of the Well-H baseline APE with the Well-J shifted APE (assuming three times the original amount of asphaltene) shows that both APE upper boundaries intersect the isothermal line of 100 °C at a similar position. Switching an anchor point on the baseline APE of Well-J model to compare with the shifted Well-H APE (assuming one fifth of the original amount of asphaltene), the predicted Well-H APE behaves similarly with the Well-J baseline APE that does not intersect the isothermal line at 100 °C. Consequently, both models can reproduce the overall trends of asphaltene precipitation risk as a function of asphaltene content. The transition-zone-fluid’s APE (e.g., Well-J) can move to the platform-interior-fluid’s APE (e.g., Well-H) with increasing asphaltene content and vice versa.

5. Discussion

5.1. Lessons Learned from Pitfalls

To secure robust oil production from the aspect of total flow assurance, it is important to understand the phase behavior of asphaltene, which is a sequential process of initial precipitation, followed by aggregation, and ultimately deposition, after which point larger problems are noted in daily production operations. Precipitation is an essential phenomenon that triggers deposition. The onset condition (usually observed from the AOP) is a primary piece of information to estimate the risk associated with asphaltene precipitation in industrial engineering because of its simple acquisition, whereas no direct link is available regarding asphaltene deposition. This provides conservative countermeasures; however, they require a balance to avoid undertaking radical management changes with costly overruns or over-conservative decisions such as project cancelation. A flow assurance engineering team should therefore involve a balanced approach to appropriately handle asphaltene issue from a multidisciplinary perspective to avoid biased sense of a single discipline.

This paper presents three case studies related to gas injection projects in which some operational conditions were subject to precipitation risks. In the case study-1, if countermeasures were oriented from the facility engineering approach, an advanced investment of an injection pump or asphaltene inhibitor could be applied with excessive caution to mitigate potential risks prior to actual issues. However, the advanced investment will be wasted if no asphaltene issues occur. Conversely, if any preparatory countermeasures are not undertaken, the project profit will deteriorate upon encountering asphaltene issues because of the production opportunity loss owing to the long installation time required for a chemical injection pump from scratch. For this reason, the case study-1 provides the minimal recommendation for simply preparing an installation location at an offshore platform as a form of compromise and cost-effective risk management. There is another aspect to consider from the reservoir engineering approach of aiming for higher oil recovery and the production/facility engineering approach of aiming to have
a more robust operation with minimized asphaltene risks. The evaluation concludes that natural gas (i.e., the driest gas) has the smallest operational risks. However, the highest oil recovery can be expected by the associated gas (i.e., the wettest gas), which might be preferred by reservoir engineering discipline. The compromised choice could therefore be to use mixed gas to satisfy risk mitigation and oil recovery. This is a typical case for recognizing a pitfall that depends on different discipline viewpoints.

The case study-2 was a part of the case study-1 and revealed a useful technique to estimate a pseudo APE as a possible conservative scenario by incorporating all experimental findings in the absence of data acquisition. No AOP detection in isothermal depressurizing measurements means that APE boundaries do not intersect the isothermal P-T line on the thermodynamic diagram. If plural isothermal depressurization tests are performed with no detection, a possible position of the APE can be more easily defined on the thermodynamic diagram. This technique is a hypothesis-wise approach; however, it is worthy to make risk evaluation possible on the thermodynamic plot.

The case study-3 is another typical example to recognize a hidden pitfall in the background of standard asphaltene evaluation in which AOP is experimentally measured as a static assessment assuming various gas mixing ratios. The key to managing the pitfall is already commonly used as the standard concept, such as fluid dynamics from a reservoir engineering perspective. The VGD process should be incorporated into the gas injection assessment to more practically estimate asphaltene precipitation risks. The modeling analyses show that the APE can expand as the injection gas is enriched through the VGD process. This results in the bottomhole operating condition of GIP production wells move into an expanded-APE trajectory from a location originally out of the area. A high asphaltene precipitation risk is identified at the time of gas breakthrough in which the most accumulation of enriched injection gas occurs. To make risk variation more predictable, the dynamic asphaltene precipitation behavior must be investigated by considering changes of the injection gas composition.

The case study-4 exposes a typical geochemical pitfall. Simple and typically uneven asphaltene risks in an identical field have been known by engineers in the case of isolated layers or gravity segregation followed by diffusion. However, this common perspective did not work in this case study. Therefore, a more complicated scenario, in which risks distributed not only vertically but also horizontally, was assumed and succeeded without contradiction. The assumed mechanism included multiple oil migration and/or sudden pressure decline owing to temporary seal break of the cap rock. The current risks for asphaltene precipitation were linked to past geological events. This understanding contributes to the appropriate development of the subject oil field. Otherwise, the unclear situation of uneven asphaltene risk distribution would require more conservative countermeasures in an even lower risk area, which would lead to excessive costs.

5.2. Insight from Technical Innovations

The pitfalls discussed in this paper were unavoidable in the past owing to an over simplified understanding of asphaltene as the most complex component in hydrocarbon. A brief history of asphaltene research is presented here. From the aspect of molecular understanding (Fig. 13, modified from Morimoto’s work\(^{63}\)), the first mention of this topic in academic society was the definition of turpentine oil-soluble components in 1837\(^{64}\). The simple definitions such as toluene-soluble and heptane-insoluble material are still used even now; however, this situation implies that a large part of truths still remained in poorly understood black box. Further insight has been elucidated with continuous technological progress using various analysis techniques such as X-ray diffraction (XRD), nuclear magnetic resonance (NMR), and field ionization mass spectrometry (FI-MS). Asphaltene molecular models proposed were updated from the simple one by Yen\(^{65}\) to more complex and realistic ones\(^{66}\)\(^{69}\) such as continental- and archipelago types. Informatics techniques have been introduced in the petroleum industry\(^{70}\) followed by recent innovations that enable estimation of the asphaltene molecular structure by Fourier transform ion cyclotron resonance mass spectrometry (FT-ICR-MS)\(^{71}\)\(^{72}\) and taking photographs of asphaltene molecules by atomic force microscope and scanning tunneling microscopy (AFM/STM)\(^{73}\)\(^{75}\).

Now a new era of informatics is available for asphaltene-related issues in the petroleum industry. More applications in advance from downstream disciplines are now considered by upstream sectors. As shown in Fig. 14, for pre- and/or initial elucidation of the black box (i.e., unrecognized asphaltene truth), upstream engineers recognized problems in limited areas such as production and flow assurance. However, for the post-elucidation, asphaltene have been recognized as a key component, which can be widely involved in many mechanisms such as wettability alteration and low salinity water EOR processes. Furthermore, the function of the wettability alteration mechanism might be linked to a more important theme of special-core-analysis (SCAL), which provides crucial data for field evaluation. The most recent understanding of molecular-level details is expected gearing up from conventional analytical approaches towards sophisticated ones, enlarging the overlap of various engineering disciplines, which will bring more interactive exchange of ideas. These innovative ideas will assist in more accurately identifying pitfalls of asphaltene evaluation.
6. Conclusions

Four case studies demonstrate how multidisciplinary studies practically contribute to addressing asphaltene issues in the field. In this paper, we consider multi directional eyes covering flow assurance-, reservoir-, production-, facility-engineering, and geoscience that can highlight overlooked issues that might have otherwise remained obscure from a single-disciplinary prospective. To advance each study, numerical modelling was effectively applied to compensate for the lack of experimental observations that are typically costly and time-consuming. The first through third cases involve preparatory asphaltene risk assessment for a future gas injection project. Various types of injection gases and mixing ratios were assessed by comparing the operating conditions and APEs. The last case involves understanding the mechanism to generate uneven asphaltene deposition. 

Fig. 13  Research History of Asphaltene Molecules(53)–(80)

Fig. 14  Asphaltenes Involved in Various Mechanisms in Industry(7), (81)–(83)
risk distribution in the unique field. All key findings and useful deliverables are summarized below:

- With increasing injection gas mixing ratio, all APEs expanded but asphaltene risks depended on the type of injection gas because some cases could offset APE expansion by shifting the saturation pressure line away from the surface operating conditions. This maintained the lower APE boundary as the original position or distant location from the surface operating conditions.
- The study recommendations can be debatable from various viewpoints of different disciplines. The conflict should be compromised to maximize the project value: more oil recoverable gas is used even under risky production operation conditions and vice versa.
- Offshore development cases should particularly consider preventive mitigation plans because of the difficulty of quick remedial action required for improving the wellhead platform design (such as installation space and electrical supply for a chemical pump).
- Failure to experimentally obtain AOP is also useful information for considering the possible asphaltene risk.
- The common industrial approach of static asphaltene evaluation does not always correctly characterize the precipitation risk even though actual asphaltene deposits are observed at a subject well. To address this anomaly, a dynamic investigation of APE is recommended by accounting for the VGD process.
- Uneven asphaltene risk distribution scenarios can be possibly explained in consideration of geological events, such as multiple oil migration events and/or seal breaks. Understanding the various location risks is valuable for optimum development planning.

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Nomenclatures

\[ \psi \times 6.894757E + 00 = \text{kPa} \]
\[ \left( ^\circ \text{F} - 32 \right)/1.8 = \text{°C} \]
\[ \left( ^\circ \text{F} + 459.67 \right)/1.8 = \text{K} \]

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要  旨

アスファルテンフローアシュアランスにおけるリスク
一いかに評価の陥斎を見抜くか？ー

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油田におけるアスファルテン析出リスクに関するケーススタディ4例を通じて、多専門領域横断アプローチによりいかに析出リスク評価を行う上での陥斎を最小化していくかを論議した。一般的なアプローチではアスファルテンリスク評価における致命的要素を見逃してしばしば陥斎に陥るが、これを避けるため、本論文では実際に事例をどのように実際に現場で起きている現象を解釈するかを紹介する。アスファルテン析出圧力（AOP）実験計測値で校正したアスファルテン含有流体の状態方程式モデルを用い、アスファルテン析出エンベロープ（APE）をPT相の図上に示し、開発シナリオがAPEに与える影響の感度解析を行った。分析には圧入ガス種類、ガス混合率、気化ガスドライプロセスのような流体力学、アスファルテン含有量の地域的分布などを感度パラメーターとした。これらの分析を通じ、単一専門分野の視点では見逃すことのできない陥斎ポテンシャルを抽出し以下の洞察を得た。1）ガス圧入時のアスファルテンリスクはドライガスとすることで相殺傾向を示す。2）気化ガスドライプによる圧入ガスのエンリッチ化を考慮する必要がある。3）エンリッチ化ガスあるいはリーンガスの坑井近傍への塩積といった流体力学の時変化がアスファルテンリスクを変動させる。4）校正用 AOP データが不足する場合に実験観測に矛盾しない擬似 APE 推定は有用である。5）油マイグレーション地質史とアスファルテンリスクの分布傾向には相関がある。