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Faculty of Science and Technology

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Abstract

This master thesis is describing the theoretical & analytical principles of pipeline installation. In the literature survey stage we elaborate on basic information about different types of offshore pipelines. Installation also plays an important and vital role. Therefore in the next step we introduce various installation methods for offshore pipelines and what may govern the choice of an installation method / scenario. Then guidelines and constrains for establishing the different installation methods are matters of our concerns.

Calculations for two different cases related to documenting installation of steel pipelines and flexible pipelines in sideway current are included. The S-lay pipeline installation method will be taken for the analysis in the 2 case study of this thesis. Analysis will be carried out in 2 steps. First step is a static analysis and the second is a dynamic analysis. Fortunately the program OrcaFlex is capable to do both analyses.

The stinger elements are modeled as points which are held by links/tethers in both vertical and lateral directions. The links are restricted to only accept tension forces without any shear forces or bending moments. The idea is that these links will act as “roller” restraints.

Tension forces in a vertical link will represent stinger roller reactions when the pipe is sitting on the roller, and zero force will represent a pipe lift-off. Same criteria apply to the lateral links. Tension in a lateral link will represent a lateral reaction which is due to lateral forces on the pipe. These lateral links are simple but very useful components for the model to reach its equilibrium during iterations.

The upper end of the pipeline is fixed to the barge and will not accept torsion. This end represents the barge tensioner. The bottom end of the pipeline is pinned to the seabed with no torsion allowed and will represent an anchored end.

Different direction scenarios will be taken for the current. In this project the directions will be 0°, 30°, 60°, 90°, 120°, 150°, and 180°. Cases presented will be named based on these directions. OrcaFlex outputs will be observed to find out which scenario gives the “worst” condition during pipe-lay.

Acknowledgement

This thesis work is prepared to fulfill the requirement in the Master of Science degree in the Faculty of Natural Science and Technology in University of Stavanger.

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Last but not least, I would like to sincerely and special thank my friends and my family for everything. Your supports, your loves and the laughs are things that keep me going forward. I would not make it without you all.

Mina Karimi
June 26th, 2012
Stavanger, Norway

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Chapter 1 – Introduction

1.1 Historic overview of offshore field development [1]

Oil has been used for over five thousand years. In the Middle East, oil seeping up through the ground was used in waterproofing boats and baskets, in paints, lighting and even for medication.

Whale oil has been used in more recent times as a source of light in houses. However, the high premium for whale oil decimated whale populations and as their numbers dropped the prices rose further.

The demand for oil was then far higher than the supply. Many companies and individuals were looking for an alternative and longer lasting source of what would later become kno
wn as black gold. Apart from a brief period of coal oil, the answer came with the development of drilling for crude oil. Onshore oil wells were first and as demand continued to grow exploration companies began to look below the sea bed.

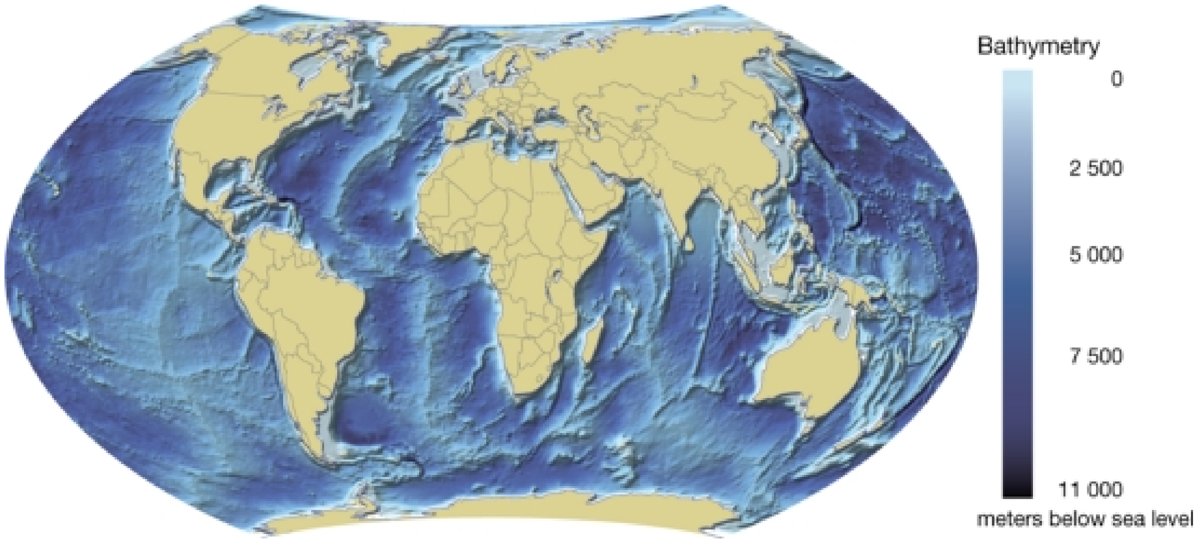

Figure 1.1 Map of the world based on sea level. Elevation indicated by the color scale [1]

Before World War II, offshore activity was limited to drilling in shallow waters of Lake Maracaibo, Venezuela and the swamps and coastal area of Louisiana in the US. In the mid-1940s, significant changes in the oil industry were made as America was making its transition from a war-time to a peace-time economy. The petroleum industry witnessed the end of government controls on crude-oil prices, and the states began disputes over offshore water bottom ownership. There was a large public demand for oil and gas, and offshore exploration encountered challenges, such as underwater exploration, weather forecasting, tidal and current prediction, drilling location determination and offshore communications.

Despite the difficulties, the first well was drilled from a fixed platform offshore out-of-sight of land in 1947. Its barge and platform combination was a major breakthrough in drilling-unit design for offshore use. This event marked the beginning of the modern offshore industry as it is known today.

The first oil well structures to be built in open waters in the Gulf of Mexico were in water depths of up to 100 m (Figure 1.1) and where constructed as a piled jacket structure in which a framed template has piles driven through it to pin the structure to the sea bed. To this, a support frame was added as the working parts of the rig to support the deck and accommodation. These structures were the fore-runners for the massive platforms that now stand in very deep water and in many locations around the world, including the North Sea.

The 1960s were boom years for the oil industry with many new offshore oil and gas provinces being discovered - the Gulf of Mexico, the Southern North Sea, the South China Sea, Australia and the Gulf of Suez.

Two “oil shocks” of the 1970 led to dramatic increases in oil prices and a perception that oil was in short supply.

The 1970s and early 1980s were years of unprecedented offshore activity. The stimulation of high oil prices and a perceived need to increase security of oil supplies made possible the installation of giant platforms in the hostile waters of the Northern North Sea and offshore Alaska, and in the deeper waters of the Gulf of Mexico (Figure 1.2).

The collapse of the oil prices in 1986 put the future of such offshore development into question. The industry responded with innovative solutions that enabled new developments to go ahead, but with little prospects of any change in oil prices in the foreseeable future. The industry was then facing growing concerns over safety and environmental issues [1].

Although large volumes of oil and natural gas lie offshore few new “giant” offshore fields may be discovered. Therefore the industry must look towards smaller fields, often with complex geology, and in remote and frontier areas, for example in deep water. To develop these resources economically, the industry has to find new solutions that combine cost-effectiveness over the lifetime of the project with improved safety and environmental performance.

Figure 1.2 Most offshore activities are concentrated in a few basins likethe Gulf of Mexico [1]

1.2 Current activities and trends [1]

Most offshore activities are concentrated in a few basins; the North Sea, the Gulf of Mexico(Figure 1.2), the South China Sea, offshore Brazil and offshore West Africa. The North Sea has been the largest producing region of the offshore oil industry. Most of the reservoirs are in water less than 200 metres deep, although some deep water fields are being developed offshore Norway and West of Shetland. A major feature of production in this region is the development of “satellite fields” - generally small accumulations which lie close to existing production facilities.

Current focus is the deep offshore area beyond the continental shelf where water depths reach some 3000 metres. Gulf of Mexico, offshore Brazil and West Africa are the locations for many record breaking developments in the deep offshore.

The industry is also active in “frontier” areas such as offshore Alaska and the Barents Sea offshore Norway. These areas are among the world's most hostile environments where remoteness, deep water, high winds, floating ice and sub-zero temperatures are just some of the challenges facing the industry. Some arctic regions are frozen for up to 10 months of the year, putting severe limitations on drilling activities.

The opening up of the former USSR to Western companies has led to an increased interest in the large hydrocarbon resources there. Some estimates suggest that the Russian continental shelf could hold more than a fifth of the world's offshore oil and gas resources; to date, only a small part of the area has been explored. A number of oil and gas fields have been discovered in the Sea of Okhotsk north of Japan and in the Barents and Kara Seas in the Russian Arctic, among which are one of world scale.

A serious accident occurred in the Gulf of Mexico 20.04.2010. The “Deepwater Horizon” drilling rig explosion killed 11 platform workers and injured 17 others. The explosion was followed by a sea-floor blow-out and an oil spill that is said to be the largest marine oil spill in the history of the petroleum industry.
The leak was stopped 15.07.2010 by capping the blowing well after release of the order of 5 million barrels (800.000 m^3) of oil [1].

1.3 Mature areas versus frontier areas [2]

Depending on the degree of maturity of the different areas, there is some variation in the types of challenges involved in realising the commercial potential of undiscovered offshore resources.

Characteristics of mature areas include familiar geology (Figure 1.3), fewer technological challenges and well developed or planned infrastructure. The discovery rate is high, but major new discoveries are less likely. There have been petroleum activities in parts of the mature area of the continental shelf for many years. This means that the geology in these areas is well documented, and the infrastructure is for the most part highly developed.

Frontier areas are characterised by little knowledge of the geology (Figure 1.3), significant technical challenges and lack of infrastructure. The uncertainty surrounding exploration activity is greater here, but there is still the possibility of making substantial new discoveries in these areas.

The companies allowed to explore in the frontier areas must have broad-based experience, technical and geological expertise, and a solid financial base.

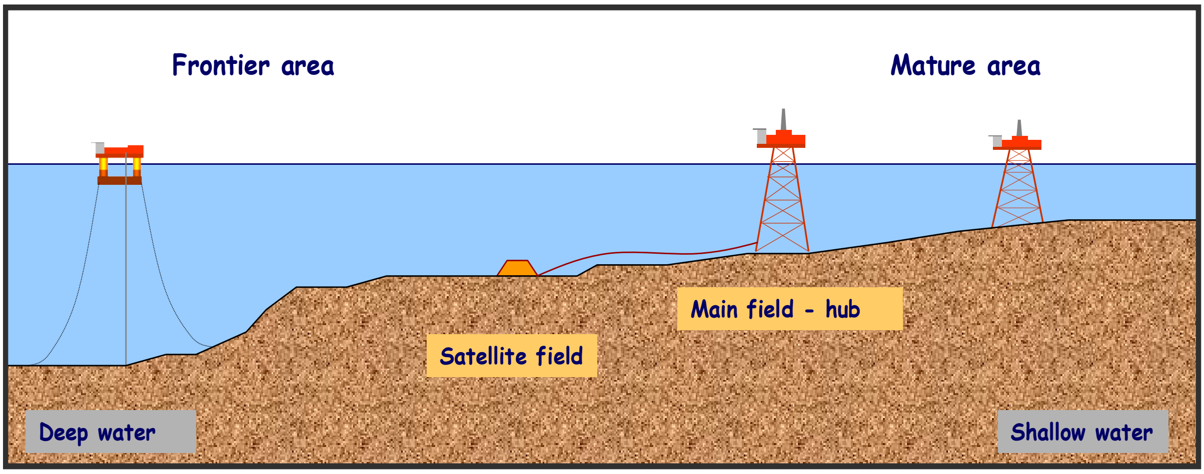

Figure 1.3 Characteristics of mature areas include familiar geology and frontier areas are characterised by little knowledge of the geology [1]

The expansion of deepwater developments into frontier areas with no existing infrastructure has always been a challenge.

The development of the offshore oil industry in hostile waters has been made possible by many achievements comparable with the space industry. Many fields are located far from land. New fields are being explored in ever deeper and wilder waters, like the Norwegian Sea and the Atlantic Ocean west of Scotland [2].

1.4 The North Sea & the Norwegian Continental Shelf (NCS)

In 1959 the massive Groningen land gas field was discovered in the Netherlands. Geologists estimated that the same rock formations might be found beneath the southern North Sea basin in UK waters. They were right and gas was discovered off the English East Coast in the 1960s. Indications around the coast of Greenland gave geologists the idea that there may be oil and gas around Scottish waters [1].

There have been land oil wells in Europe since the 1920s. It wasn't until the 1960s that exploration in the North Sea really begun, without success in the early years. They finally struck oil in 1969 and have been discovering new fields ever since. The subsequent development of the North Sea is one of the greatest investment projects in the world. (Figure 1.4)

Production on the Norwegian continental shelf has been dominated by a few large fields. When the North Sea was opened up for petroleum activity, the most promising areas were explored first. This led to world-class discoveries which were then put into production, and were given names such as Ekofisk, Statfjord, Oseberg, Gullfaks and Troll. (Figure 1.5)

These fields have been, and still are, of great significance for the development of the petroleum activities. The large fields have contributed to the establishment of infrastructure that subsequent fields have been able to tie into [2].Recently a large new filed was discovered west off Stavanger.

Figure 1.4 The subsequent development of the North Sea is one of the greatest investment projects in the world [1]

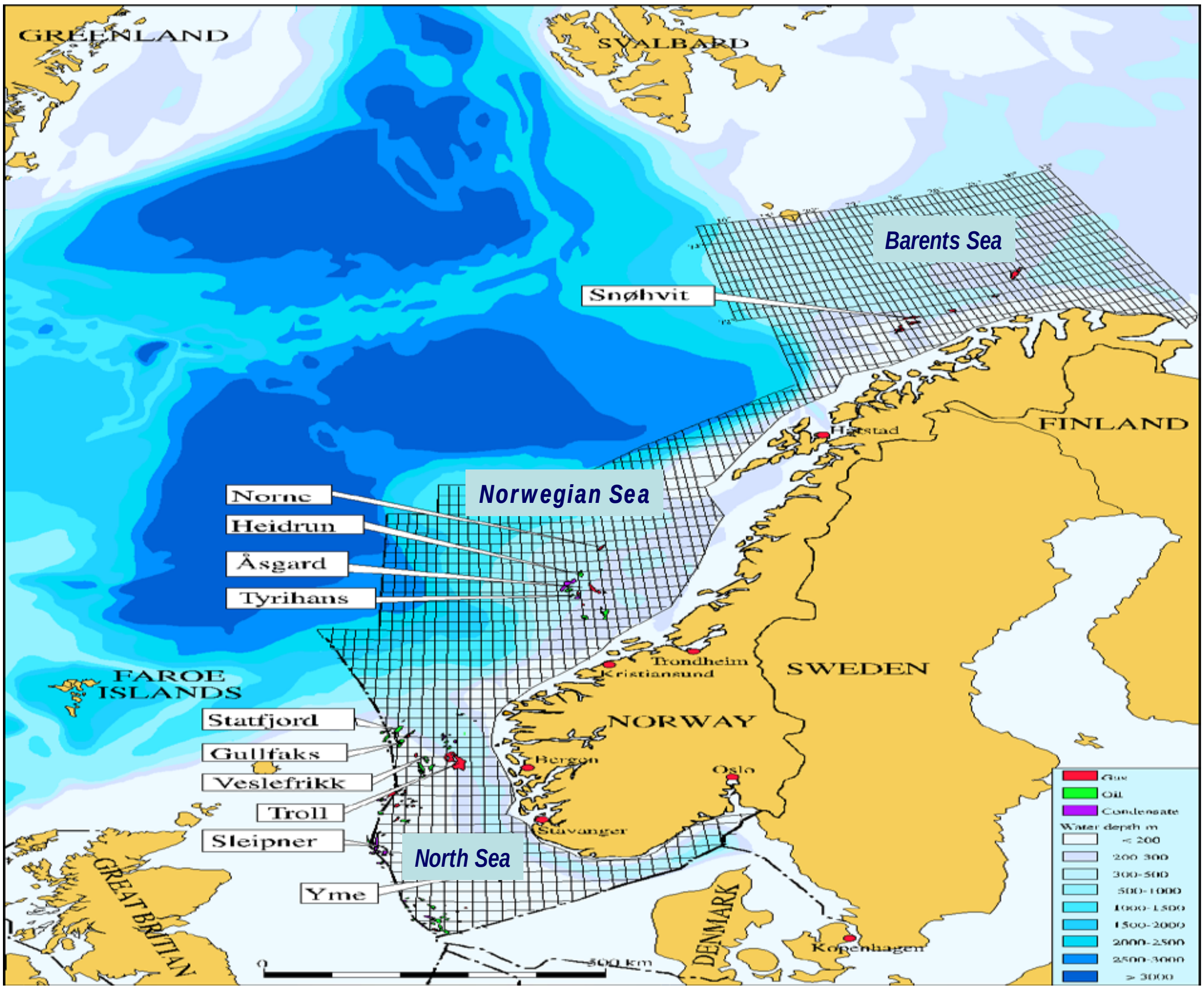

Figure 1.5 Production on the Norwegian continental shelf has been dominated by a few large fields[1]

Chapter 2 - Offshore pipelines and steel risers

2.1 Offshore pipelines

2.1.1 Historical background

The first pipeline was built in the United States in 1859 to transport crude oil (Wolbert, 1952). Through the one-and-a-half century of pipeline operating practice, the petroleum industry has proven that pipelines are by far the most economical means of large scale overland transportation for crude oil, natural gas, and their products, clearly superior to rail and truck transportation over competing routes, given large quantities to be moved on a regular basis. Transporting petroleum fluids with pipelines is a continuous and reliable operation. Pipelines have demonstrated an ability to adapt to a wide variety of environments including remote areas and hostile environments. Because of their superior flexibility to the alternatives, with very minor exceptions, largely due to local peculiarities, most refineries are served by one or more pipelines [40].

2.1.2 Purposes of using pipelines

Pipelines are used for a number of purposes in the development of offshore hydrocarbon recourses. (Figure 2.1): These include:

- Export pipelines;
- Flowlines to transfer product from a platform to export lines;
- Water injection or chemical injection flowlines;
- Flowlines to transfer product between platform, subsea manifold and satellites wells;
- Pipeline bundles.

The design process for each type of lines in general terms is the same. Design of metallic risers is similar to pipeline design, although different analysis tools and design criteria are applied [39].

Route selection is the first and vital activity in design of pipeline because a poorly chosen route can be much more expensive than a well-chosen route.
But there are a lot factors that we should pay attention during route selection such as: Politics, area of very hard and very soft seabed, cables, manifolds, pockmarks, fishing and also crossing of existing pipelines. For choosing the best route for pipeline we should have complete information about seabed topography and geotechnics.

The construction of an offshore pipeline involves several engineering disciplines. Once the need for a new pipeline has been established, the project starts with the design engineer, who usually selects the diameter, wall thickness, steel grade, the method of manufacture and the method of installation [16].

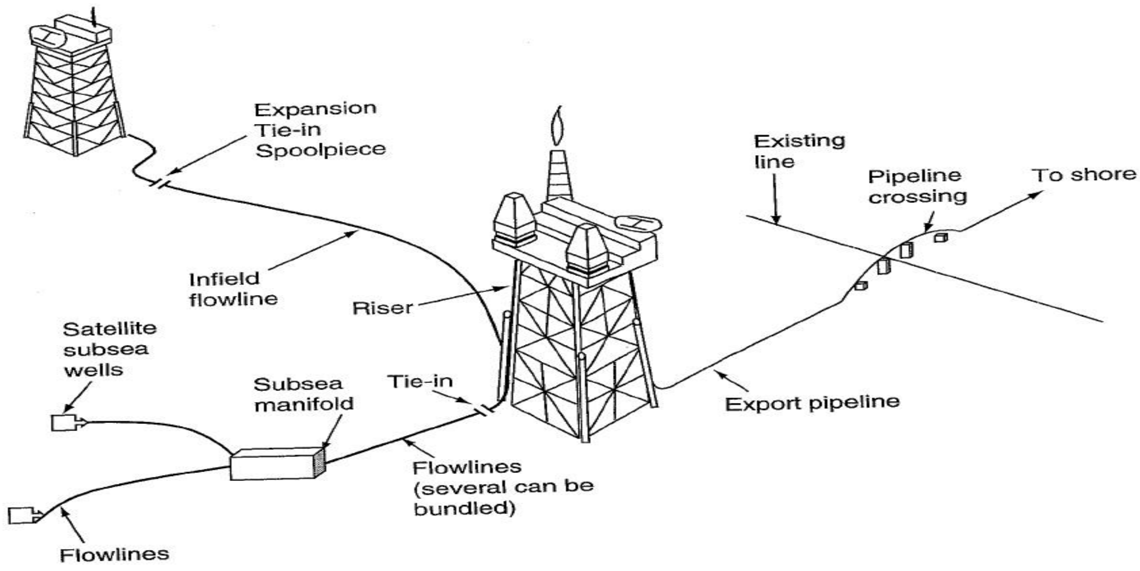

Figure 2.1 Use of flowline offshore [39]

2.1.3 Pipeline Design [40]

Design of offshore pipelines is usually carried out in three stages:

- Conceptual engineering,
- Preliminary engineering, and
- Detail engineering.

During the conceptual engineering stage, issues of technical feasibility and constraints on the system design and construction are addressed. Potential difficulties are revealed and non-viable options are eliminated.

Required information for the forthcoming design and construction are identified. The outcome of the conceptual engineering allows for scheduling of development and a rough estimate of associated cost. The preliminary engineering defines system concept (pipeline size and grade), prepares authority applications, and provides design details sufficient to order pipeline. In the detail engineering phase, the design is completed in sufficient detail to define the technical input for all procurement and construction tendering. The materials covered in this book fit mostly into the preliminary engineering.

A complete pipeline design includes pipeline sizing (diameter and wall thickness) and material grade selection based on analyses of stress, hydrodynamic stability, span, thermal insulation, corrosion and stability coating, and riser specification [41].

Table 2.1 shows sizes of some pipelines. This table also gives order of magnitude of typical diameter/wall thickness ratios (D/t). Smaller diameter pipes are often flowlines with high design pressure leading to D/t ratio between 15 and 20. For deepwater, transmission lines D/t of 25 to 30 are more common. Depending upon types, some pipelines are bundled and others are thermal- or concrete-coated steel pipes to reduce heat loss and increase stability.

Table 2.1 Sample pipeline size [40]

Project No.	Project Name	Pipeline Diameter (in)	Wall Thickness (in)	D/t	Design Criterion
1	Zinc	4	0.438	10	Internal pressure
2	GC 108-AGIP	6	0.562	12	Internal pressure
3	Zinc	8	0.500	17	Internal pressure
4	Amerada Hess	8	0.500	17	Internal pressure
5	Viosca Knoll	8	0.562	15	Internal pressure
6	Vancouver	10	0.410	26	External pressure
7	Marlim	12	0.712	18	External pressure
8	Palawan	20	0.812	25	External pressure
9	Palawan	24	0.375	64(2)	Internal pressure
10	Marlim	26	0.938	28	External pressure
11	Palawan	30	0.500	60(2)	Internal pressure
12	Shtockman	36	1.225	29	Internal pressure(1)
13	Talinpu	56	0.750	72(2)	Internal pressure(1)
14	Marlim	38	1.312	29	External pressure(1)
15	Shtockman	44	1.500	29	Internal pressure(1)
16	Talinpu	56	0.750	75(2)	Internal pressure(1)

Notes:
1. Buckle arrestors required.
2. Pipelines with D/t over 30.5 float in water without coating.

Although sophisticated engineering tools involving finite element simulations [39] are available to engineers for pipeline design, for procedure transparency.

2.2 Flowlines and risers

The term subsea flowlines is used to describe the submarine pipelines carrying oil and gas products from the wellhead to the riser base (Figure 2.2); the riser is connected to the processing facilities (for example a fixed platform or a floating platform). The conservation of fluid flow and the ability to restart production as fast as possible is a prime concern for the operation of any hydrocarbon production system [42].

Risers can in some cases simply be regarded as a continuation of the subsea flowlines from the riser base on the sea bottom to the surface facilities. However, in the case of floating production units the risers must be flexible enough to accommodate the motions caused by waves, wind and current [43]. Risers are therefore tailor-made for the production unit and are therefore described in more detailed in conjunction with floating production systems [44].

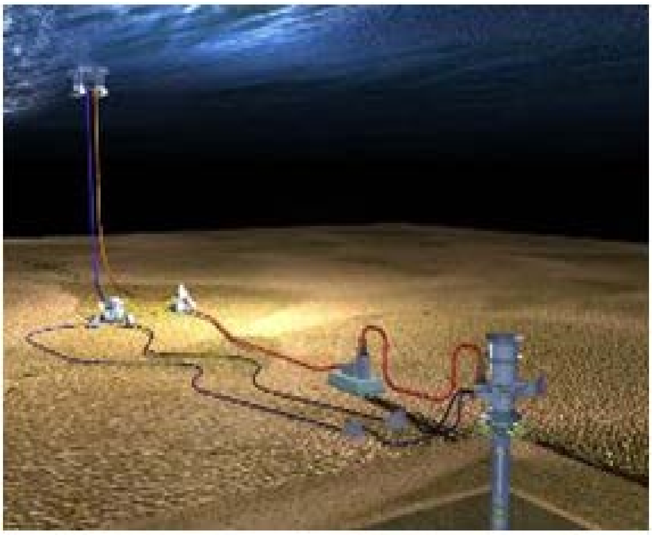

Figure 2.2 Subsea Flowlines connect a wellhead to a riser system [42]

2.2.1 Design challenges for flowline systems

As offshore oil and gas production is moving into deeper waters, the risk of hydrate plugging and wax formation in flowlines increases, as does the cost of remediating any such plugs [45].

Hydrate and wax formation in subsea flowlines will cause undesired fluid properties and even blocking of the wellstream, which implies shutdown and comprehensive reparations [46]. Keeping the well fluids from cooling down will prevent serious problems like the formation of gas hydrates and wax.

There are several solutions to prevent formation of hydrates and wax during production. In the North Sea, the most common method combines thermal insulation and chemical injection. The disadvantage with this is that large amounts of chemicals are injected continuously into the well stream, then have to be removed again at the topside. This process incurs considerable operational costs, and may represent a risk to the environment [1].

Conventional methods of preventing hydrate plugs, including blowdowns, hot oiling and chemical injection are costly and not entirely reliable. For example, at locations where the subsea manifold is higher than the riser base, or locations where the flowline route has substantial high and low spots to trap gas, the process of venting gas is very complex. Electric heating can be an attractive alternative for both prevention and remediation of hydrate plugs having potentially high reliability and little adverse operational impact [1].

2.2.2 Electric heating of flowlines

Planned or unexpected shutdowns of a pipeline imply an effluent temperature reduction and a risk or reaching critical temperatures, such as the hydrate appearance temperature (HAT) or the wax appearance temperature (WAT).

The operator will choose to work with fluids at temperature above the HAT/WAT and allow himself a margin to take into account cooling in case of a production stop (Figure 2.3). Operationally with this margin is defined as a number of hours called the “cooldown time” that the operator requires before having to start up a preservation scheme to replace the hydrate-prone fluids inside the flowlines with inert (“dead”) oil [47].

Figure 2.3 Hydrate removals from pipeline [47]

Electric heating is developed as a method for removing hydrates, and is also applicable for solving plug situations [46]. Electric heating may also prove effective in preventing or remediating wax plugging. In this case it may be possible to reduce capital costs by replacing conventional pigging loops with single heated flowlines.
Two systems are considered:

- Direct electric heating (DEH), Figure2.4, with strap-on piggyback cable and current carrying pipeline
- Indirect electric heating of pipelines using a) cables as ohmic elements or b) induction heating of pipeline wall. In both cases the cables are embedded inside the thermal insulation. [1]

In a DEH system, the pipe to be heated is an active conductor in the electric circuit formed by the dynamic DEH riser cable, the armored feeder cables, the piggyback cable, and the flowline. The heating effect results from the fact that an electric current flowing in a metallic conductor generates heat.

AC current comes from the topside power system through the DEH riser cable. For safety and reliability reasons, the heating system is electrically connected to surrounding seawater (i.e. it is an "open system") through several sacrificial anodes. These anodes must be rated for both corrosion protection and for sufficient grounding of the system during the expected lifetime of the flowline and the service life of the heating system [49].

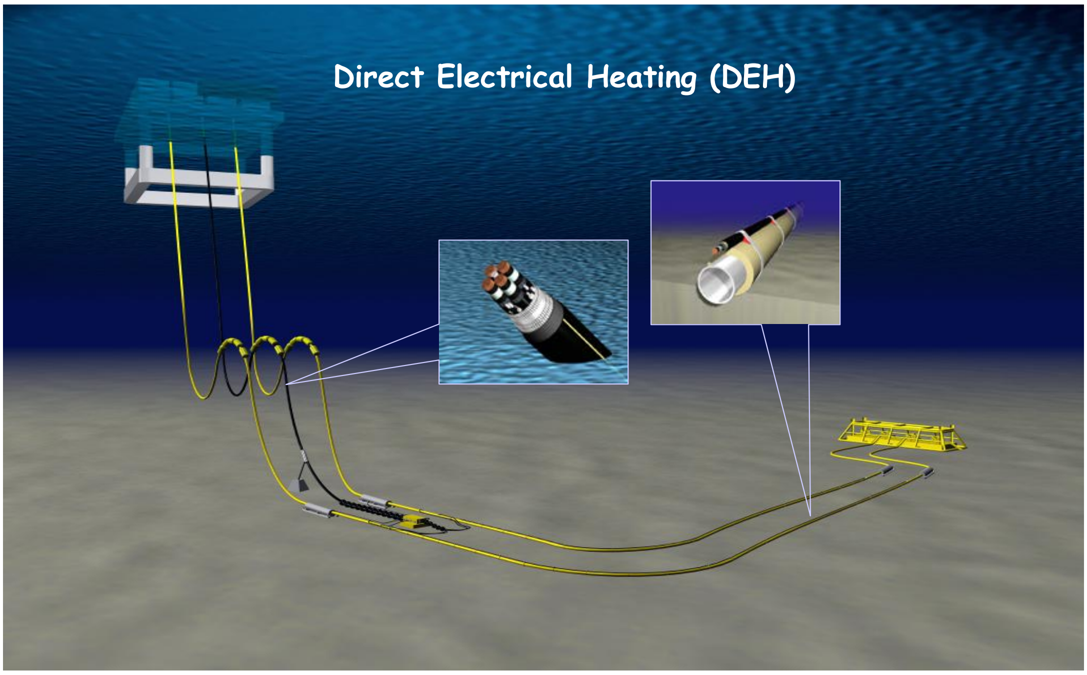

Figure 2.4 Direct Electrical Heating [1]

2.3 Risers

A riser is a pipe or assembly of flexible or rigid pipes used to transfer produced fluids from the seabed to surface facilities, and transfer injection or control fluids from the surface facilities to the seabed [50]. Riser connects subsea to topside [12].

There are different types of risers [12]:

- ❖ Drilling Risers - Typically top tensioned risers

- ❖ Production risers
  - Flexible risers
  - Steel catenary risers
  - Hybrid riser towers
  - Single Hybrid Risers – SLOR
  - Grouped SLOR

- ❖ Export risers
  - Similar to production risers

- ❖ Water/Gas Injection risers
  - Similar to production risers

2.3.1 Drilling Risers - Typically top tensioned risers (TTRs)

A drilling riser (Figure 2.5) is a conduit that provides a temporary extension of a subsea oil well to a surface drilling facility. Drilling risers are categorized into two types: marine drilling risers used with subsea blowout preventer (BOP) and generally used by floating drilling vessels; and tie-back drilling risers used with a surface BOP and generally deployed from fixed platforms or very stable floating platforms like a spar or tension leg platform (TLP).

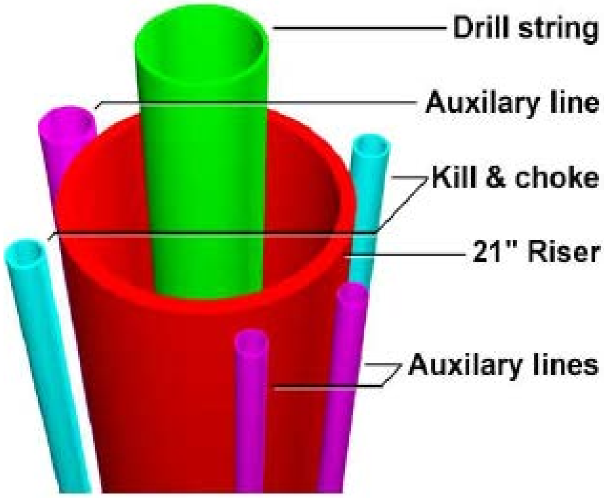

Figure 2.5 Drilling riser joints with buoyancy modules [51]

Some characteristics of this kind of riser are listed below [12]:

- Surface Trees - full well pressure
- Extensive track record
- In use in 300-2500m
- Tensioning system needed
- Mixed string concept introduced

2.3.2 Flexible risers

Flexible pipes have been successful solutions for deep and shallow water riser and flowline systems worldwide. In such applications the flexible pipe section may be used along the entire riser length or limited to short dynamic sections such as jumpers.

Many of the analysis methods and design techniques developed for flexible pipe in the early 1980s have been extensively developed and enhanced by, for example, 2H Offshore Company to meet the challenges offered by steel catenary risers. These same methods are now routinely applied to flexible pipe allowing efficient and accurate assessment of flexible pipe response even under the most severe and complex loading conditions [52].

Some characteristics of this kind of riser are listed below [12]:

- Extensive track record (85% of all dynamic risers are flexible)
- In use in 2000 m
- Large installation vessel fleet available
- Easy to install
- Flexible - robust, high dynamics
- Corrosion resistant/reusable
- Pipe-in-pipe/heated under development

There are lots of configurations of flexible risers as you can see in Figures 2.6 and 2.7[12].

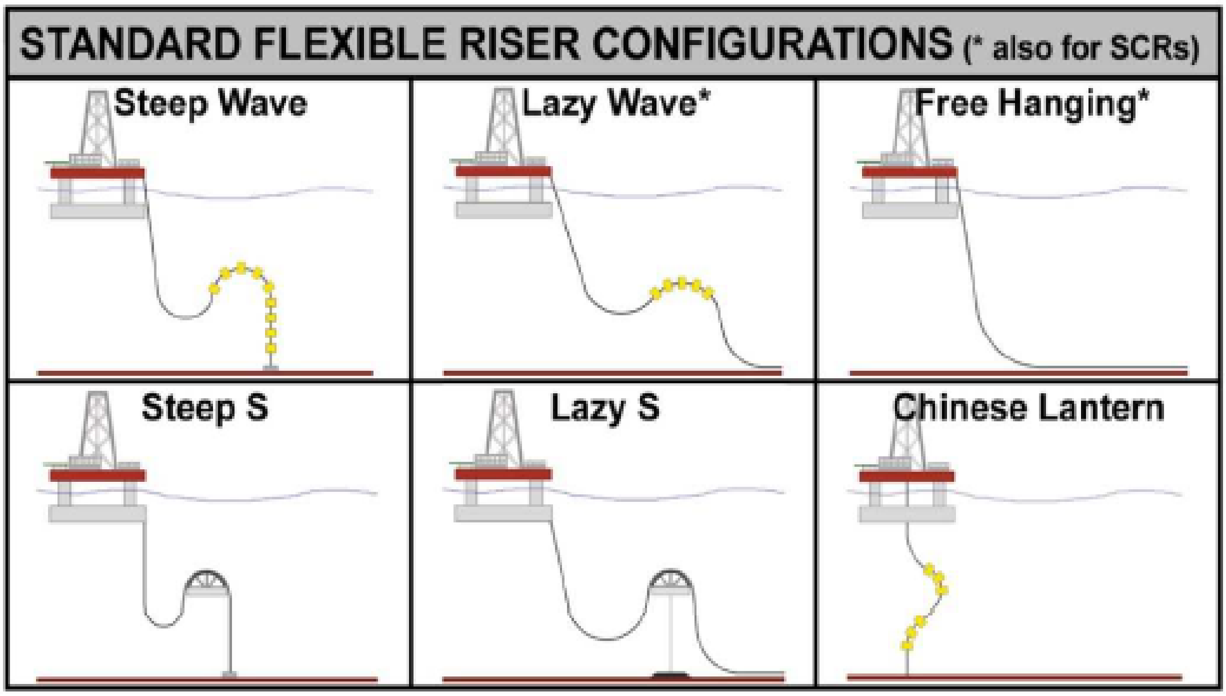

Figure 2.6 Standard flexible riser configurations [12]

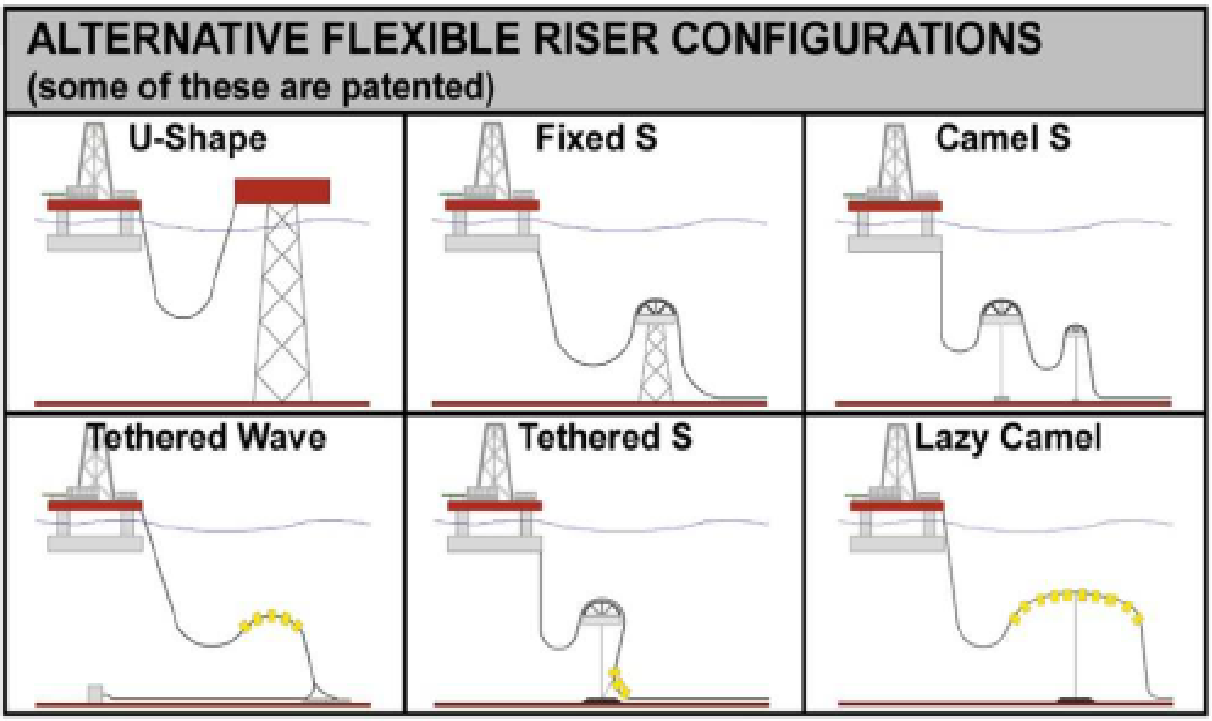

Figure 2.7 Alternative flexible riser configurations [12]

2.3.3 Steel catenary risers

2.3.3.1 Characteristic of Steel catenary risers

Riser systems can form a significant proportion of the development costs of floating production systems, which are increasingly being considered for current and future field developments. Steel catenary risers offer a low cost alternative to conventionally used rigid and flexible risers on floating platforms and can also provide economic riser design solutions for fixed platforms [54].

A Steel Catenary Riser (SCR) is a prolongation of a sub-sea pipeline attached to a floating production structure in a catenary shape. SCR lines are commonly subjected to fatigue loads, particularly in the touchdown zone, due to platform movements, Vortex Induced Vibrations (VIV) and sea currents.

In order to avoid any excessive stress concentration, the oil and gas industry pays particular attention to the welding process of SCRs in order to minimize any possible misalignment between pipe ends (Hi/Lo). To facilitate this operation, some companies such as Tenaris Company provide stringent ID end tolerances through specific processes such as Cold End Sizing and Machining and offers high accuracy Laser End Measurement System (LEMS). (Figure 2.8)

Any excessive weight in the production system could impact on the required dimensions of the floating production structure. Tenaris Company produce high-quality high-strength steels of up to X70 Sour Service and up to X100 Non Sour, allowing the wall thickness of the line to be reduced and hence reducing the weight of the column [53].

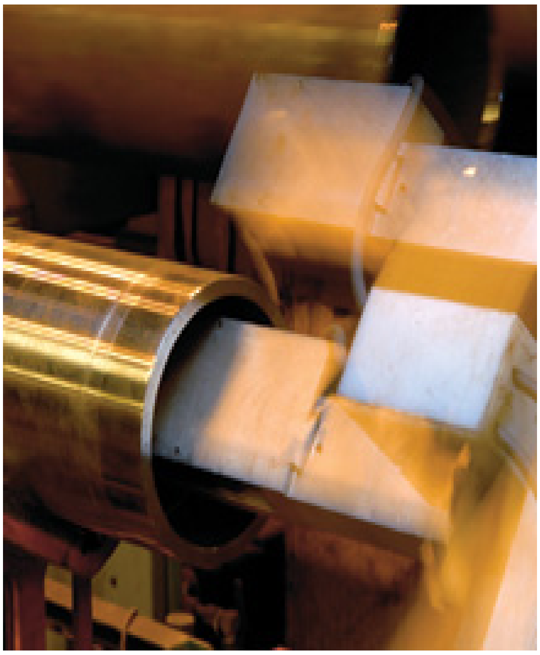

Figure 2.8 Laser End Measurement Systems [53]

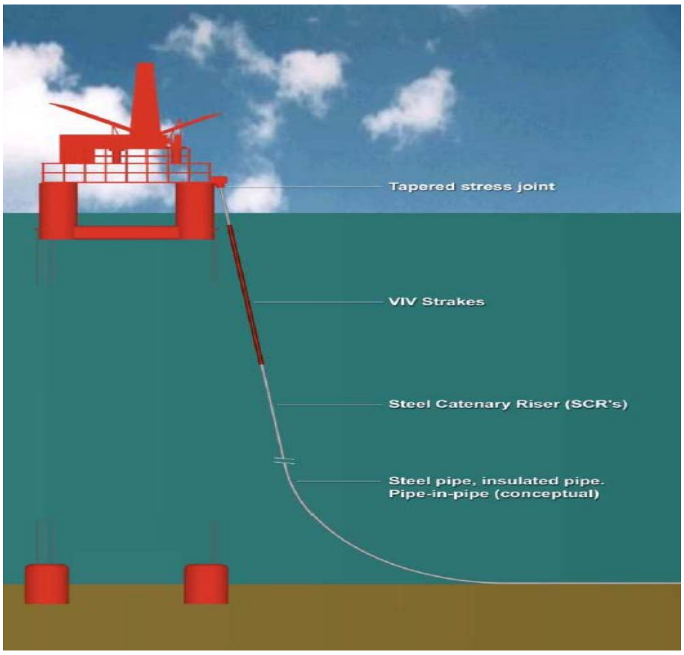

Figure 2.9 Steel catenary risers [12]

Some characteristics of this kind of riser are listed below [12]:

- In use in 500-2500m

- TLPs, SPARs GOM & Semis Brazil
- J/S-lay, reeling
- Many installation companies
- Low material cost
- Available in large diameters
- High pressure/temperature
- Internal inspection
- Pipe-in-pipe/heated under development
- Well known material properties

2.3.3.2 Steel catenary riser type [55]

Several types of steel catenary riser have been developed, each having characteristics which make it better suited for particular applications.
Four types of steel catenary riser are considered and are illustrated in Figure 2.10, these are:

- ✓ Simple Catenary Riser
- ✓ Buoyant Wave or Lazy Wave Riser
- ✓ Steep Wave Riser
- ✓ Bottom Weighted Riser

Although not a true catenary, the bottom weighted riser has very similar characteristics to a simple catenary.

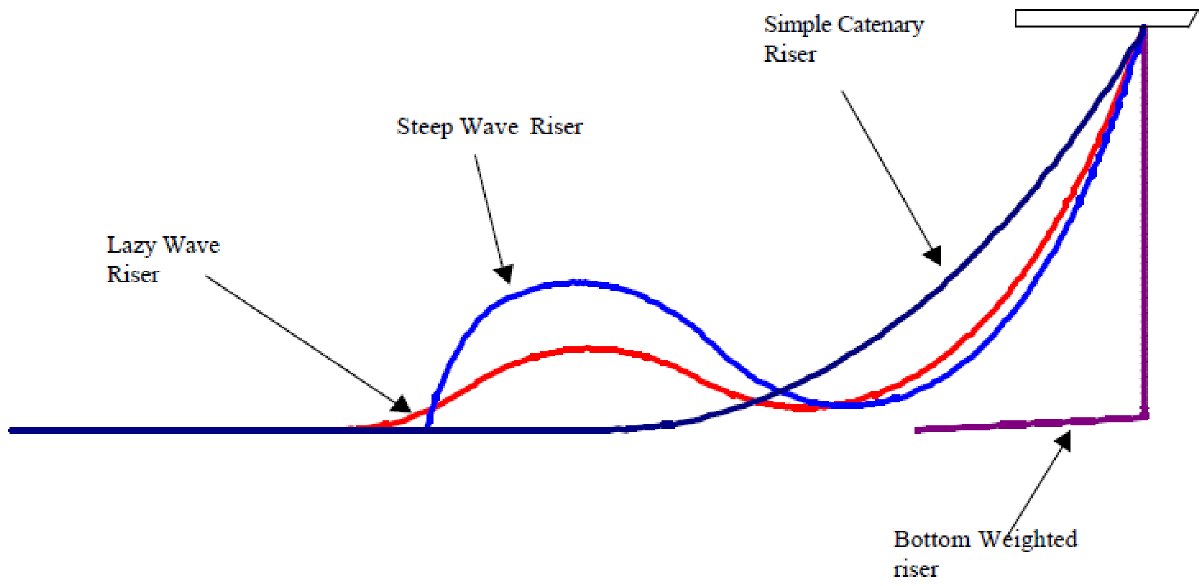

Figure 2.10 Simple Catenary, Buoyant wave, Lazy Wave and Bottom Weighted Risers [55]

✓ **<u>Simple Catenary Riser</u>**

This is a simple drape starting at the vessel and curving through nearly 90 degrees to a horizontal orientation on the seabed. A flex joint is required at the vessel interface and some length of the pipe is required on the seabed before any seabed termination/flowline connection. This length allows for any movements caused by changes in vessel position with the actual length required dependent on the amount of vessel drift (Figure 2.11). Alternatively, the riser can extend to become part of the flowline without any end termination or pipeline connection.

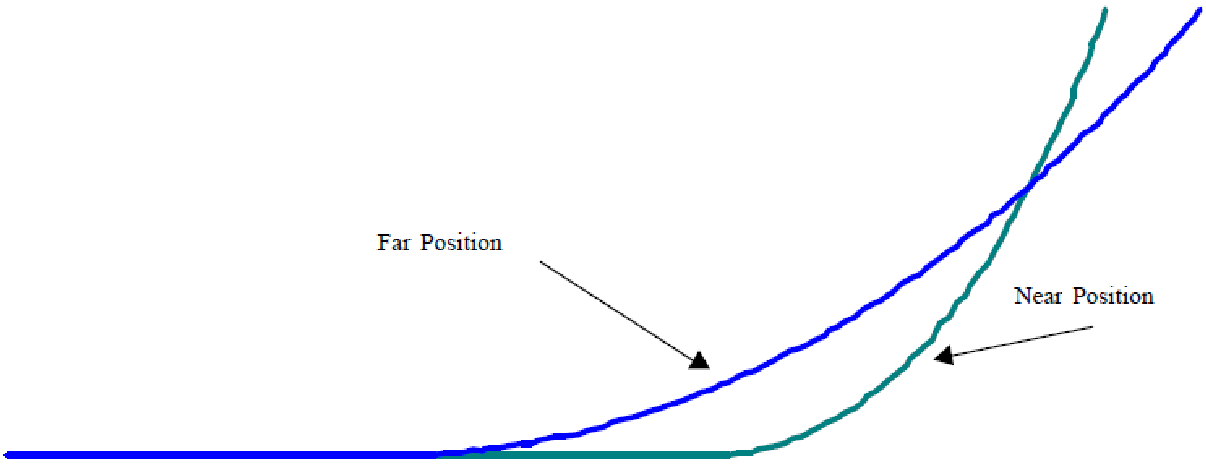

Figure 2.11 Simple Catenary Risers in Near and Far Positions [55]

- ✓ **Buoyant Wave or Lazy Wave Riser**

The buoyant wave riser is similar to the simple catenary except that it has additional suspended length supported by a buoyant section. This forms an arch prior to the touch down point on the seabed. The buoyant wave riser also requires a length of pipe on the seabed before (if any) the seabed termination.

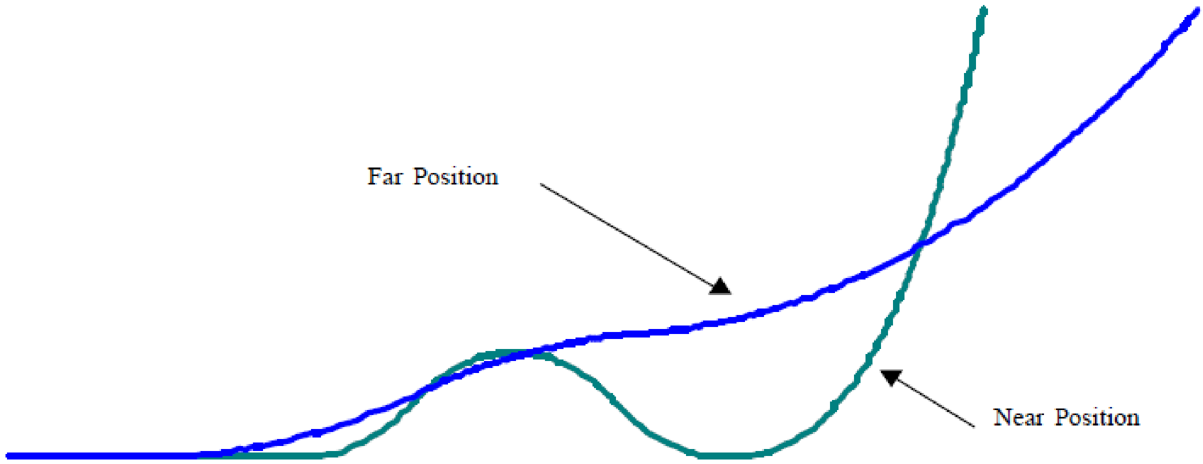

Figure 2.12 Buoyant Wave Risers in Near and Far Positions [55]

- ✓ **Steep Wave Riser**

The steep wave riser is similar to the buoyant wave riser in that it also has arch formed using buoyancy. The steep wave riser is not orientated horizontally on the seabed as the other catenary risers are but terminates vertically into a structure fixed to the seabed. This riser type requires a stress joint or flex joint at the base where bending loads can be high. The seabed interface is closer to the vessel compared with the other catenary risers and is fixed, whereas the touchdown point for the simple and buoyant wave catenaries can move.

✓ **Bottom Weighted Riser**

The bottom weighted riser is similar to a simple catenary and consists of a vertical and a near horizontal section joined by a rigid elbow and flex joint arrangement. The near horizontal section is made of titanium and has flex joints at either end; the lower end is connected to a piled end termination. A small amount of buoyancy is added to make the near horizontal section neutrally buoyant, and a tether is used at the elbow to help stabilize the vertical section. The bottom weighted riser has the capacity to accommodate higher vessel motions and current loading than the buoyant wave or simple catenary risers, making it particularly suited to large diameter export lines (>20in) connected to an FPSO in shallow water depths (400-800m).

Several types of steel catenary riser exist and each has characteristics affecting its suitability for a particular application. There are many factors which influence the response of the selected catenary and these should be considered carefully during the riser design.

In harsh environments such as West of Shetland and Northern Norway, simple catenary risers are suitable for heave restrained TLP and Spar platforms. Buoyant wave risers are more suitable for FPSO applications where vessel offsets are larger (20%-30% water depth). Bottom weighted risers are suitable for large diameter export lines in shallow water depths (400-800m).

Both simple catenaries and buoyant wave risers can be used in a wide range of water depths. However, shallower water depths (400-800m) present difficulties which may require slight modifications of the riser in places such as the use of increased pipe weight or higher grade material. In benign environments such as the Gulf of Mexico or West Africa less modification is required.

Some issues such as VIV and catenary seabed interaction require more research to enable a better understanding of these phenomena to be established. Studies are being undertaken at present to achieve this.

There are many design difficulties associated with steel catenary risers but with careful engineering a workable solution can be found.

2.3.4 Hybrid riser towers

A Hybrid Riser system consists of a vertical pipe attached to the sea-floor by gravity and suction piles and held in tension with buoyancy tanks connected at the top of the riser. One outstanding advantage of the Hybrid Riser concept is the possibility of using disconnectable turret and decoupled risers, providing flexibility in case of delays during the construction of the FPSO and also allowing the FPSO to move in case of hurricanes. Furthermore, the Hybrid Riser allows reduced fatigue loads compared to a standard Steel Catenary riser design, representing a potentially interesting solution in challenging environments, such as deep-water and/or sour service conditions [53].

2.3.5 Grouped Single Line Offset Riser (SLOR)

The Grouped SLOR consists of individual free standing risers, Single Line Offset Riser (SLOR) and/or Concentric Offset (COR) grouped together by a buoyant guide frame tethered down at either ends to suction piles. Connection between the vessel and the SLOR or COR is provided by a flexible jumper from a gooseneck located at the top of the riser assembly [56].

The Grouped SLOR has great potential for large deepwater developments, which typically have a complex and congested seabed layout immediately adjacent to the production vessel. This is due to the large number of risers and umbilical often required to meet production and export requirement, and the spatial constraints imposed by mooring lines and vessel offsets. This poses significant constraints on the riser design to achieve an acceptable riser arrangement whilst ensuring that clashing and interference are avoided [56]. In addition, the fatigue requirements, stringent insulation and gas lift requirements (use of concentric riser system) greatly favors the use of Grouped SLOR.

One of the benefits of the Grouped SLOR system is the flexibility of installation. The riser buoyant guide frame and its associated components (e.g. buoyancy tanks, tethers, etc.) can be towed out or transport by barge, and preinstalled on site prior to receiving the riser system. The SLOR (including COR) system can be subsequently installed by either towing, J-laying or reel laying.

Once the individual SLOR/COR is installed in the guide frame via the receptacle, the flexible jumper is installed. The jumper can either be clamped onto the SLOR/COR while waiting for the arrival of the production vessel or “hook up” to the vessel by pulling it into the I or J-tube and terminating [56].

Figure 2.13 Grouped SLOR [56]

Some characteristics of this kind of riser are listed below [12]:

- Deepwater applications

- Local fabrication and assembly
- For ships & semis
- Flexible configuration
- Insulation/flow assurance
- Small subsea footprint and hang-off area
- Vessel loads lower than for flexibles/SCRs
- Controlled onshore fabrication
- Low in-place stresses
- Low cost installation vessels
- Buoyancy tank
- Connected directly to FPS
- Light Weight Material

Chapter 3 - Flexible pipes

3.1 Flexible pipe basics

Two generically different type of construction are available:

- Unbounded Flexible: where the armour components are allowed to slide relatively to the polymer layers.
  Prime reference for the design of this type of structure is API 17J and B.
- Bonded Flexible: where the cross-section is monolithic. These types of lines are currently used as flexible hoses in export system.
  Prime reference for the design of this type of structure is API 17K.

This part will only covers the first type because they are the most complex one and the most interesting one for the type of complex field.

A flexible pipe generally combines low bending stiffness with high axial stiffness, which is achieve by a composite pipe wall construction. The two basic components are helical armouring layers, which bring the structural capacity of the pipe, and polymer sealing layers, which ensure water tightness of the bore fluids but also from ambient seawater [5]. This combination of material allows for a much smaller radius of curvature than for a steel pipe with the same pressure capacity.

Generally, a flexible pipe is designed specifically for each application and is not an off-the-shelf product, although they may be grouped according to specific designs and hence applications. This allows the pipe to be optimised for each application. Flexible pipes are sized according to their ID in the range of 2 – 20 inches.

3.2 Material Selection

Material selection is an important part of the Flexible pipe design; general criteria for their selection will be introduced in this part. The associated material to a specific layer must fulfil its function and hence ensure that the integrity of the flexible pipe is maintained during its service life. Although this must be the primary criterion of material selection, the manufacturer and designer have many secondary criteria to consider which could influence the final selection.

Among other criteria, the functional suitability of the material refers to its ability to fulfil its mechanical requirements in the overall pipe design while resisting attack from the internal and external environment [5]. The internal contents of flexible risers range from seawater to very severe multiphase fluids. In addition to the natural fluids experienced in oil production, many additives such as various types of inhibitors may also be present during the operational life of the risers.

Also functions of the internal conditions are the temperature and pressure requirements of the system.The temperatures experienced during normal oil production are not sufficiently high to cause concern with respect to the metallic materials; however, the temperature restrictions of the plastic materials provide a basic design criterion which must be closely adhered to especially regarding the long-term plastic ageing effect at high temperatures.

The pressure rating of the system will dictate not only the thickness or the steel layers but can also influence the grade of material. Depending on the nature of the internal fluids (sweet or sour service), higher grades of steel may be specified in systems where extreme pressures induce high stresses in the steel layers [4].

Hence main criterions for Material Selection are maintain integrity during service life , functional requirements, long-term integrity, ease of manufacture and supply, certification requirement, client specification, economic viability, ...

3.3. Types of pipe

Two generically different type of pipe are available:

- Rough bore
- Smooth bore

Rough bore (Figure 3.1) is comparing to smooth bore has high collapse resistance (in-place, in tensioner, over chutes), permeation of gas through liner will not cause collapse on depressurisation. This type of pipe is suitable for fluids containing gas; it is piggable however it is heavier, stiffer and more expensive.

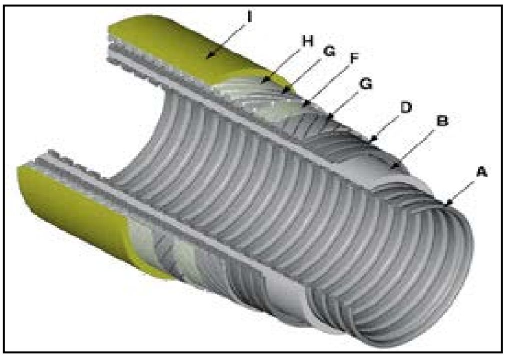

Figure 3.1 Flexible Rough bore [12]

Smooth bore (Figure 3.2) has very low collapse resistance, it can cause problems in tensioner and over chutes, gas permeation through liner can cause collapse if depressurised therefore it is not suitable for fluids containing gas (i.e. water injection only) [5]. This type of pipe is better from flow assurance aspect and also it is lighter and cheaper. It may include an extra layer over the pressure armour to stop hydrostatic pressure acting on the fluid barrier.

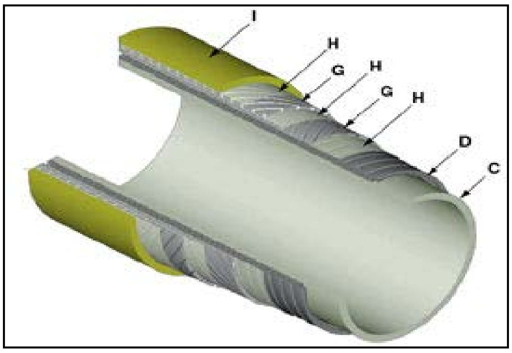

Figure 3.2 Flexible Smooth bore [12]

Pipes are classified in 3 different families according table 3.1:

Table 3.1 Families of flexible pipeline [6]

	FAMILY II	FAMILY I + III	
Parameter	Flowlines with combined tensile and pressure armour	Flowlines with steel strip pressure armour	Flowlines and risers with C-shape pressure armour
Design Pressure	Up to 3,000 psi *	Up to 7.500 psi	Up to 15 ,000 psi
Design Temperature	-50°C - +130°C	-50°C - +130°C	-50°C - +130°C
Pipe Size (ID)	4" ID - 8" ID *	2½" ID - 16" ID	2½" ID – 16" ID
Fluid	oil/gas/water/chemicals	oil/gas/water/chemicals	oil/gas/water/chemicals

** Boundaries may be expanded on a project basis following design review.*

Design pressures are from 15,000 psi for the smallest pipe bores to 5,000 psi for the largest. NKT Flexibles is the industry leader in design and manufacture of flexible pipes for high temperature applications with design temperatures as high as 130°C for both static and dynamic service.

According table 3.2 today usually spoke of family II and III depending whether or not they have a pressure retaining layer. [6][7]

Table 3.2 Families and layers that used in them [6]

FLEXIBLE PIPE FAMILIES	FAMILY I	FAMILY II	FAMILY III
	Smoothbore	Rough Bore	Rough Bore High Pressure
Carcass		•	•
Inner Liner	•	•	•
Pressure Armour	•		•
Crosswound Tensile Armour	•	•	•
Outer Sheath	•	•	•

Our present pipe size range is from 2.5 inches to 16 inches inner diameter.

3.4. Layer by layer investigation

Pipe made up of a series of unbounded layers, each layer does its own particular job. Layers in a flexible pipe may consist of (Figure 3.3):

- Carcass.
- Fluid barrier (Inner liner).
- Pressure armour.
- Tensile armour.
- Intermediate sheath(s).

- Insulation.
- Outer sheath.

Note: Plastic layers are thermoplastic [6].

The space delimited by the inner liner and the outer-sheath is called annulus.

Figure 3.3 Pipe made up of a series of unbounded layers [6]

3.4.1 Carcass

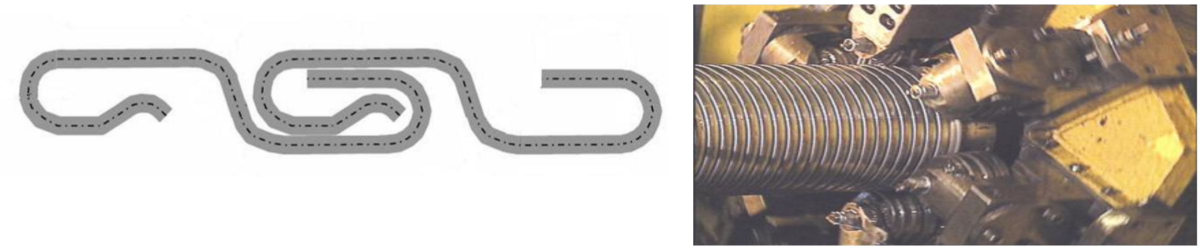

Figure 3.4 Carcass is the only metallic layer in contact with the bore fluid [6] [12]

This is an interlocked metallic layer which provides collapse resistance. It is made by cold forming steel strips (strip thickness from 0.6 ~ 2.4mm) into an interlocking profile. This open and permeable structure protects the inner liner from erosion and pigging tools. (Figure 3.4)

It is the only metallic layer in contact with the bore fluid. Carcass material must hence be resistant to bore fluid (Including injected chemicals and H_2S and CO_2 contents). Materials typically used are austenitic steel (304, 316L) but today must of the developments involve Lean Duplex, Duplex or Super Duplex material. Note that particular attention must be paid to qualification of Duplex but also of the welding and manufacturing process. When there is a requirement for the bore to transport Raw Seawater the only solution possible is in general Super Duplex.

Carcass is a complex formed section and is subject to cold working during manufacture therefore the properties cannot be assessed on the base material [6]. Testing is the only method to validate the properties of the section, which are often classified with respect to the T/t ratio. Carcass size and thickness (i.e. inertia) is determined by the required crush capacity and wear rate due to particulates in the fluid. It is important that locking of the carcass is prevented at all stage of the flexible life as in case of locking the load pattern is too difficult to model and integrity of the layers is not guaranteed. Additionally, ensuring that the profile can move freely prevents fatigue of the layer [8] (no locking guarantees no strain variation due to dynamic loading, curvature variation).

Carcass may also be subject to very low temperatures at well start up (As low as -50°C for short periods of time) due to gas pressure.

3.4.2 Inner Liner – Pressure Sheath

It shall be noted that sometimes to describe this specific layer the name of pressure sheath is preferred to inner liner. This is due to the fact that this layer can be made of several sub-layers of polymers. A traditional example is coflon pipes from Flexifrance / Wellstream.

On these pipes the inner liner will be made of 3 different sublayers:

- 1 sacrificial sheath above carcass (has now disappeared).
- 1 pressure sheath ensuring the bore fluid containment function
- 1 anti-creep sheath below the pressure armour.

The purpose is to limit the pressure sheath thickness reduction due to creeping. Thickness of it is from 5.5 to 18mm.

This multilayer system has led to carcass collapse failure in the past, due to pressure build-up in-between the sublayer because of permeated gas accumulation.
Important aspect in flexible is these layers will allow a certain amount of the gas species present in the pipe bore to migrate into the annulus (i.e. permeation) creating thus a highly corrosive environment in the vicinity of the steel layers when condensating.

Table 3.3 Material selection for Inner Liner – Pressure Sheath

MATERIAL	T° Resistance	Chemical Resistance	Permeation Resistance	Remarks
HDPE	--	--	--	
XLPE	-	-	-	
PA11	+	+	+	Sensitive to Hydrolysis
PVDF (Coflon)	++	++	++	

3.4.3 Pressure Armour

This is an interlocked metallic layer (Figure 3.5) which supports the internal pressure sheath and system internal pressure loads in the radial direction. A back-up pressure armour layer (generally not interlocked) also may be used for higher pressure applications. Typical materials used are carbon steels.

Wires are generally profiled and laid with a big angle on the pipe (DYNAMIC). Thickness of it is 4mm to 12mm and angle of 88° to 90°.

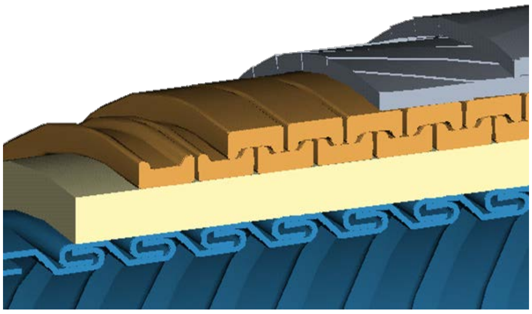

Figure 3.5 Pressure Armour [12]

Notes:

- This layer and wires can be referred with different names such as Pressure Vault or Pressure Armour Layer/Wires [5].
- Companies often do not account for the aditional collapse resistance provided by C wires, which makes their design conservative.
- Ensuring no locking of this layer when bending the pipe is also a criteria as for the carcass. This is often the limiting criteria for storage MBR definition, particularly on large diameter pipe [9].

Zeta and C wires (Figure 3.6 and 3.7) are the most commonly used profiled wires in dynamic application. No record available on in-service application involving more exotic profiles.

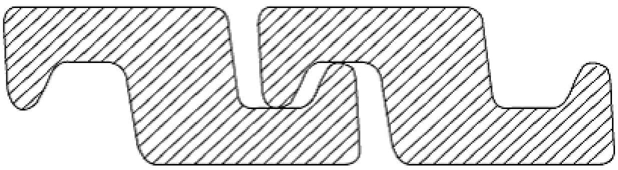

Figure 3.6 Zeta Wire (Flexifrance and Wellstream.) [6]

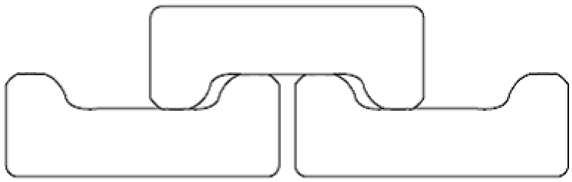

Figure 3.7 C wire [6]

Also some other profiles are under development such as Psi, K-profile, etc. for Deep-Water application.

Fatigue estimate of these profiles is usually rather complicated because it is relatively difficult to realise a small scale test arrangement that simulate the loading of this layer realistically (Nub-Nub arrangement). However, fatigue is usually not critical for this layer as dynamic motion of the pipe will not lead to high load variation because of the laying angle of these wires. The most common failure mode for these wires is generally unlocking of the profile mainly due to its asymmetry. A secondary mode is often wearing, due to contact [6].

Note that this unlocking failure mode is more critical for the Zeta wire than for the C-wires for obvious reason. In addition, C wire has also the advantage to have a big inertia leading to less risk with respect to wearing.

3.4.4 Tensile Armour

The tensile armour (sometimes only referred as armour) function is to carry axial loads from endcap and axial tension. In a riser the tensile load is a function of:

- Water Depth,
- Pipe Weight (including impact of fluid density wrt to the service condition),
- Dynamic load internal pressure.

The laying angle of the wires is a compromise to obtain the maximum combination of:

- Axial load to be carried,
- Torque balance,
- Contact pressure

Note that the higher angle is the higher support to pressure armour is brought through Vault Effect. However this will increase the fatigue loads as it increases the contact pressure.

Typically angles vary as follows:

- Static pipe: 23° to 25° (low pitch),
- Dynamic pipe: 30° to 35°
- Cross-armoured: 55° (high pitch) [10].

The amount of gap between wires is around 7-11%, smaller gap influences MBR, larger gap increases risk of non-uniform loads of pressure armour.

There are 2 types of profile for tensile armour [6]:

- Square (Figure 3.8)
- Elliptic (Flexifrance, Wellstream) (Figure 3.9)

Figure 3.8 Square tensile armour

Figure 3.9 Elliptic tensile armour

Selection of tensile armour material (Table 3.4) is based on a balance between:

- Loading resistance requirement (influenced by water depth, dynamic, etc),
- Resistance to annulus environment (H2O, CO2, H2S,etc),
- Cost.

It has to be noted that usually the load bearing capacity is reverse to the environment resistance capacity, i.e. high strength steel will have a poorer resistance to corrosion than lower class steel.This layer is critical with respect to the fatigue performance of a dynamic riser.

Quality and qualification of these wires is a focus point for Companies today due to bad experience on projects.

Welds are accounted for in Fatigue by NKT using Knock-down factors, but level of qualification is poor. Welds are today not accepted in fatigue critical area such a

Bend-stiffener and the TDP. Only, repair welds can be accepted (usually one per layer maximum).

Table3.4 Traditional material selection for Armour

MATERIAL	SMYS [MPa]	Corrosion Resistance	Denomination
Basic Steel	~600	-	NKT: Basic, Flexifrance: FI11
Sour Service	~600	++	NKT: Sour 600, Flexifrance: FI18
Sour Service (HS)	~800	+	NKT: Sour 800
High Strength	>1400	--	NKT: HSS1450; Flexifrance: FI41

3.4.5 Intermediate Layers

Figure 3.10 Intermediate Layers [12]

Additional layers have 4 main functions: fabrication aids, anti-wear layers, anti-buckling layers, insulation layers (Figure 3.10). For fabrication aids (i.e. bedding tapes) composite layers (Diolen, Viledon or Marix) are used and help maintaining sublayer between different manufacturing processes [5].

In anti-wear layer Polymer Tapes (PA11/6, PVDF, PP…) are used, optimise friction between steel layers and it s suitable for dynamic risers. In anti-buckling layer high resistance Composite tape (Aramid, etc) are used and eliminates Bird Caging of tensile layers [11].

For insulation layers material with low thermal conductivity are used to ensure specific thermal insulation properties of the pipe.

3.4.6 Outer Sheath

Outer sheath is the most thermoplastic layer and it acts like a barrier for sea water. Materials used in this sheath are PA11 (max 90°C) that has better abrasion resistance and MDPE, HDPE: (max 60°C).the thickness of this layer is from 5.5 to 10mm [11].

It is generally black or yellow and contains UV block to prevent damage from sun exposure. It may also contain burst disks (Weak points in the sheath) which will do limited damage if there is a gas build up in the annulus due to failure of the vent valves. (Only the disk will burst and not a large section of outer sheath).

What happens if the sheath breaks during installation? The outermost sheath can be repaired offshore after an expertise of the underneath layers. Anodes can be fitted to cathodically protect the armour wires. These are generally attached to the end fitting or the subsea structure [6].

Figure 3.11 Outer sheath is the most thermoplastic layer

Risers' sheaths must always be correctly repaired prior to installation. If damaged subsea the riser may need to be recovered and returned to shore or sometime replaced.

Outersheath damage can lead to dramatic failure of the pipe system because of accelerated corrosion of the tensile armour wires [5]. (Figure 3.11)

Chapter 4 – Umbilicals

4.1 Primary Functions of Umbilicals

An umbilical is defined as an assembly of fluid conduits, electrical and fibre optic cables, either on their own or in combination with each other, cabled together for flexibility (Figure 4.1). In any offshore field development, the umbilical is a critical component for the production of hydrocarbons [22].

An umbilical is thus a collection of smaller services bundled together into a single line. Since the use of floating production systems and remote wells required methods to control the wells, umbilicals provide a fixed link between the two; providing communication, power, control and injection services.

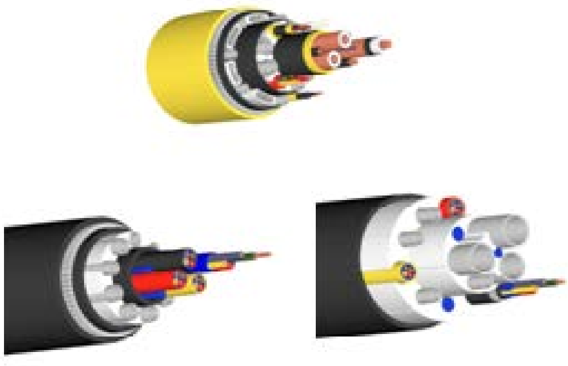

Figure 4.1 Umbilicals [23]

Umbilicals in general are vital parts of the underwater production technology. They have typical services like Hydraulic control, transfer of electrical power, electrical signal, fibre optics, chemical injection.

- Provision of electrical power for subsea pumping/ processing
- Hydraulic control system
- Electrical control system
- Data and communications
- Fluid transport
    - Hydrate inhibitors for flow assurance, most notably methanol
    - Other injection chemicals
    - Gas for re-injection, gas lift applications

The functions are provided by the individual components of the umbilical bundle [23]. These elements are designed and manufactured to meet their functional requirements prior to incorporation within an umbilical structure.

4.2 Types of Umbilicals [22]

In all umbilicals, the functional components are bundled together and an outer, Co-axial layer is applied to provide the required protection of the finished product. The mechanical design premise, and method of forming the component bundle and provision of mechanical reinforcement and outer protection varies. A general classification can be made based on the functional component type, as described in this section.

4.2.1 Thermoplastic umbilical

The bundle can contain essentially any number of components, generally including thermplastic hoses. These can be bundled together as either a continuous helix or as a twisted helix(known as SZ) to form a non-load bearing bundle. An armour package, consisting of layers of helically applied wires, is applied over the bundle to provide torsional stability, axial strength and protection from radial forces. The freedom to move of the un-bonded components within the bundle leads to a highly flexible product with excellent resistance to bending fatigue.(Figure 4.2)

Figure 4.2 Thermoplastic umbilical [22]

4.2.2 Hybrid Umbilical

This classification is necessary to recognise that it is possible to mix both steel tube and thermoplastic technologies in one product. In such cases, optimised solutions can be offered providing that the approach taken to analyse the product fully captures the mechanical characteristics of the design. (Figure 4.3)

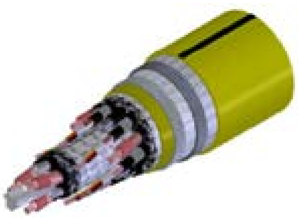

Figure 4.3 Hybrid umbilical [22]

Figure 4.4 Power umbilical [22]

4.2.3 Power Umbilical

An umbilical with high content of power cables, with or without other functions, is often termed a Power Umbilical. Power Umbilicals generally follow the same design principles as armoured thermoplastic umbilicals or steel tube umbilicals, but the loading on the cable conductors represents a significant contribution to the overall tensile capabilities of the umbilical. (Figure 4.4)

4.2.4 Steel Tube Umbilical

As the strength of a steel tube umbilical is derived from the functional tube components themselves, the design and analysis methodologies are entirely different from those for armoured thermoplastic umbilicals. Consideration is given to the share of the axial load taken by the individual functional components and extra strength members can be added to the construction to improve the load bearing capabilities of the design. For this reason, outer armouring is generally not required for steel tube umbilicals, unless there is a requirement for an increase in linear weight or additional protection from external contact forces. (Figure 4.5)

Figure 4.5 Steel Tube umbilical [22]

4.3 Configurations and Applications

4.3.1 Dynamic, Riser Umbilicals

Dynamic umbilicals, also known as umbilical risers, connect a point subsea to a point on a floating platform. The floating unit types and umbilical configuration vary widely from project to project. Common classes of floating units are Spar Boys and FPSOs (Floating Production Storage and Offloading vessels). The motions of both of these units are highly subject to wave and weather conditions. The result of this is that the umbilical will see both static and cyclic loading throughout its life. The loads are highly dependent on the vessel motions, water depth, configuration design, umbilical weight in seawater and the design of any connected hardware that can transmit loads to the umbilical [22].

In general, the prediction of mechanical properties and stress analyses of dynamic umbilicals are more critical than for static umbilicals. The reason for this is that failure of dynamic umbilicals in service may result in loss of production or have serious safety implications, whereas a static umbilical is not at risk of significant mechanical damage after installation and commissioning [24].

4.3.2 Static Umbilicals

Static umbilicals connect two points, usually subsea, and are intended to remain stable on the seabed for the entire design life. Fatigue damage in this class of umbilical can only arise from the cyclic loading seen during installation.

The number of load cycles should therefore be relatively low. As installation activities represent a significant cost in oilfield development, any reduction in requirements can be seen as a cost saving. Higher allowable loads and minimum bend radii allow installers to use shorter tensioning devices, smaller chute and reel diameters etc.

Should a Static Umbilical experience movements caused by vortex induced vibrations, a situation that could arise in case the Umbilical is free hanging over an uneven bottom, special analysis should be conducted to check potential for fatigue damage.

Chapter 5 - Offshore pipeline installation methods

5.1 Methods for pipeline installation

A very economic method of transporting oil and gas from offshore deposits is through pipeline. There are more than 60 000 miles of offshore pipelines beneath the world's oceans, and approximately 3000 miles of new pipelines are constructed each year [13]. The installation of pipelines and flowlines constitute some of the most challenging offshore operations. Sometimes innovative pipeline engineering and installation work has to carried out, taking into consideration the long distance, seabed conditions, the route selection, complexity of repair and consequences for production.

The installation of pipelines and flow lines and their connection to platforms constitute some of the most challenging marine operations.

5.1.1 S-Lay

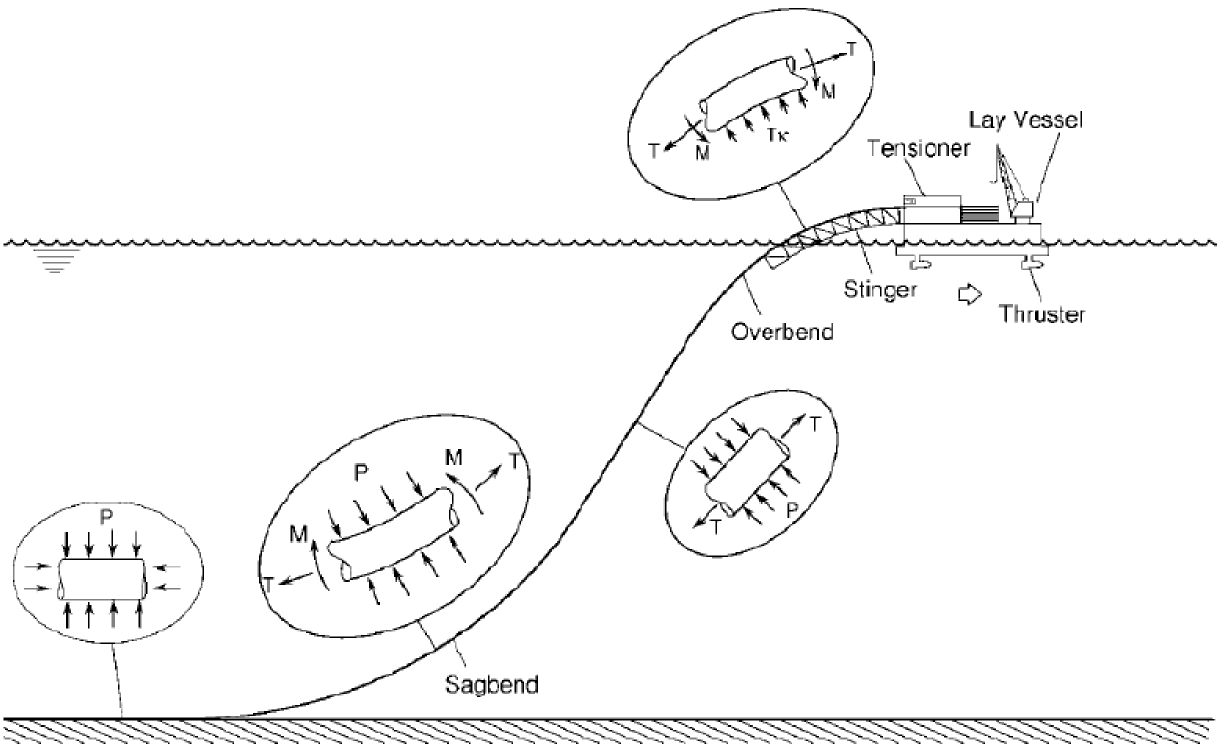

Figure 5.1 Schematic representation of S-Lay pipeline installation [15]

The S-Lay method has been developed over many years into a very efficient system for laying pipelines involving multiple work stations. S-Lay relates to an installation in which the pipeline starts in a horizontal position on the vessel and acquires a characteristic S-shape on the way to the seabed (Figure 5.1) [14]. The S-Lay method has been the main pipe installation method for water depths up to 1000m. More recently, the range of water depth for S-Lay has been nearly doubled by the design and installation of longer stinger.

The first role of the vessel is to act as a work platform for assembling the line and for storing incoming pipe lengths. Usually, a linearly-arranged series of stations weld 12-24m lengths to the free end of the line.

The welds are X-rayed and coated and the vessel moves forward, paying the line into the sea. The line leaves at the stern of the vessel via a sloping ramp (Figure 5.2). At the end of the ramp it comes in contact with a guide structure known as a stinger. The stinger is an open-frame structure that supports the line on v-shaped rollers, providing a controlled-shape transition from the horizontal to the inclined suspended section.

Older stringers were rigid, whereas modern ones are articulated. The stinger shape is prescribed by setting the segments at chosen angels. Stringer lengths vary with water depth and the submerged weight of the line. In conventional S-Lay they can reach 100m. The suspended length of pipeline is held by tensioners that are usually located on the ramp (Figure 5.2) [16].

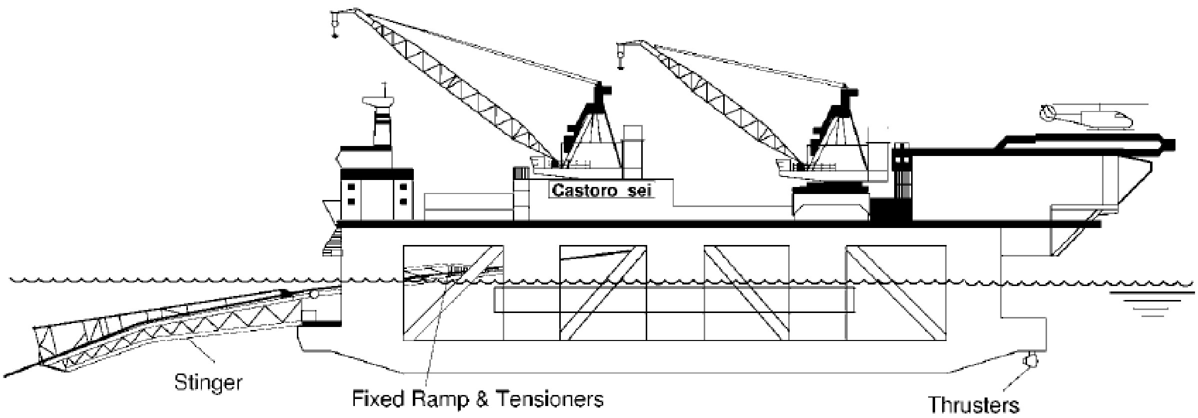

Figure 5.2 Saipem's Castro Sei semi-submersible S-lay vessel [15]

Figure 5.3 Typical tensioner used for S-Lay [15]

The pipe is leaving the stinger by rotation of the tracks, as shown in the figure above. In this case, the section of pipeline on the stinger experiences bending combined with relatively high tension. Too short a stinger can result in extensive bending at the end of the stinger, which can buckle the pipe, which can results in fracturing and flooding of the pipe. Flooding of the pipeline can make it too heavy to hold by the tensioners, possibly causing loss of the line to the seabed.

The upper curved area of the pipeline is known as overbend. The line leaves the stinger at a chosen angel, depending on different configuration of the stinger. Further down, it gradually bends in the opposite direction (Figure 5.1).

The maximum curvature occurs closer to the seabed in the sagbend region, which is nearly at the maximum water depth. Thus it must be ensured that the combined axial tension, bending and pressure loads can be safely sustained. The curvature in the sagbend region is controlled by the tension applied at the topside. However, excessive tension can be detrimental to the section over the stinger, perhaps plasticizing the pipe. In some cases, high lay tension can also increase the cost of the operation by requiring a larger vessel. In general, plastic deformations on either the stinger or the sagbend can cause excessive ovalization to the pipe cross section and spiraling of the pipeline on the seabed [16].

Drift off of the vessel or loss of tension for can cause extensive bending, collapse and local buckling. Local collapse, in turn, has the potential of initiating a propagating buckle (Figure 5.4). After the sagbend region, the line touches the seabed and responds to its relief.

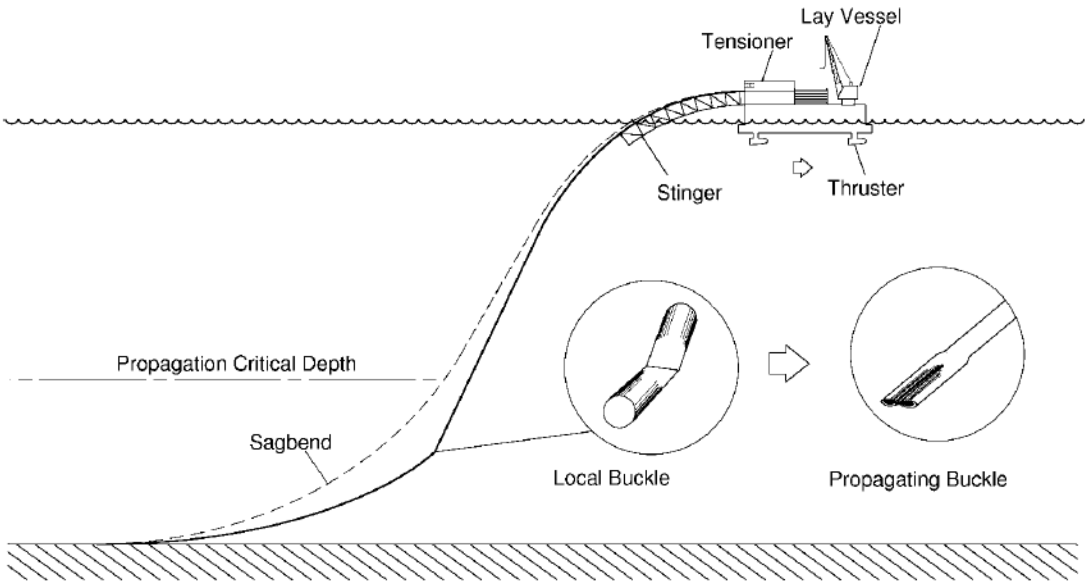

Figure 5.4 a local bending buckle during S-Lay installation [15]

One of the main roles of the lay-vessel is to provide the tension that holds the suspended line and controls its shape. In older lay barges, the tension is reacted by several long mooring lines connected to anchors. The mooring system is attached to winches, and the barge moves forward by winding in the mooring lines. This is a delicate operation essential to keeping the position and direction of the lay barge in accordance with the planned route. The loss of a mooring anchor during such an operation can cause sudden drifting of the barge, which in turn can result in buckling of the pipe at the end of the stinger due to excessive bending. More modern S-lay vessels used in deeper waters use dynamic positioning to control their position.

Dynamic positioning requires significantly more power but it increases the efficiency of the lay operation. The Castro Sei is one of the larger dynamically positioned S-Lay vessels [17]. It has as semi-submersible structure: 152m long, 70.5 m wide and has four 37 t azimuthally thrusters.

The long suspended part of the pipeline behaves like a cable rather than a beam, and its length as well as sagbend curvature are mainly governed by the water depth, the submerged weight and by tension applied at the vessel. Although modern S-lay vessels can apply very significant tensions, this comes at a significant cost to the operation. The philosophy of the installation design is first to avoid buckling failures in sagbend region, and second to keep the pipeline in the elastic regime.

5.1.2 J-Lay

As the water depth increases, the suspended length in conventional S-Lay increases, and as a result the tension that must be applied by the lay vessel goes up. In addition the required stinger length increases and its shape becomes more complex [19]. J-lay is an alternative installation method in which pipeline leaves the vessel from the nearly vertical position, as shown in Figure 5.5. On the way down to the seabed, it acquires the characteristic J-shape.

The first effect of the J-configuration is that the suspended length is reduced by comparison to the S-lay method. In this instance, the role of the tension is to support the shorter suspended length and to control the line curvature in the sagbend. A second effect is a reduced tension requirement from the vessel and a significant reduction in the required thruster power [13].

The J-lay method involves welding the pipeline together from a series of joints using one welding station and one inspection station. This results in a time consuming process, as all required work is concentrated into one workstation. For this reason, longer pipe sections are used in order to increase the efficiency of the operation.

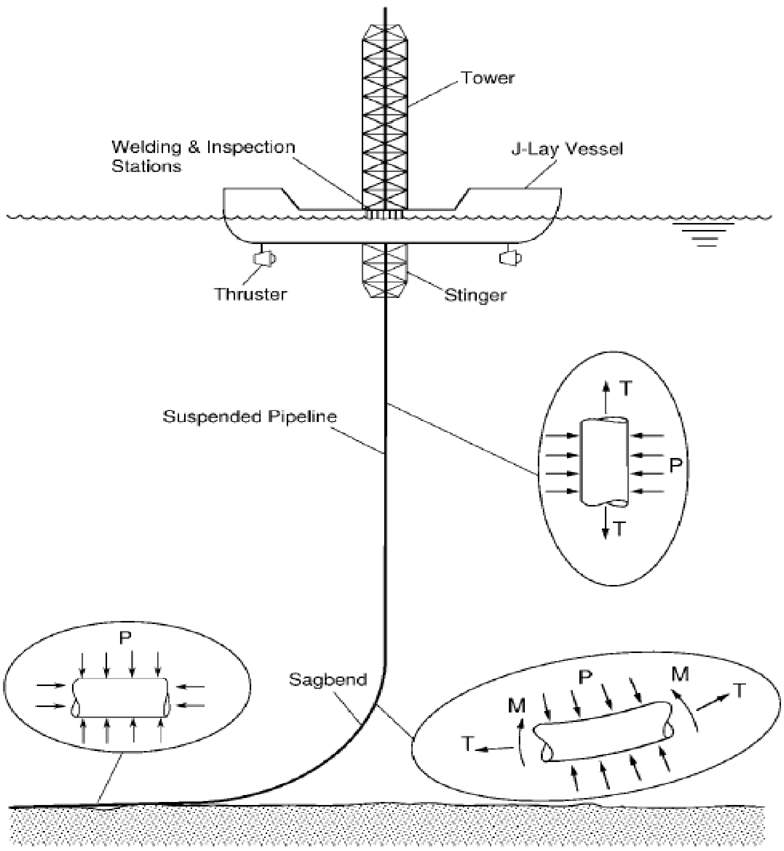

Figure 5.5 Schematic representation of J-lay pipeline installation and associated pipeline loading [15]

These usually consist of four to six 40ft (12m) sections that are pre-welded on shore. Each multiple length section is then raised to the tower (Figure 5.6), added to the suspended pipe, welded to it, inspected and coated. The long section is then lowered into the water while the vessel moves forward, installing a corresponding length to the seabed. A short guide structure (stinger) below the holding point leads the direction of the line close to the water surface. Since the touchdown point is not that far behind the vessel, the positioning of pipeline can be very precise. Better vessel control also results from the fact that only a short length of the line close to the surface is exposed to wave motions. An addition advantage is that the lower tension in the line on the seabed translates into shorter free spans [18].

J-lay is somewhat slower than traditional S-lay method, but it has been projected to be capable of installing pipelines down to 3,350 m of water depth [18]. The loads experienced by the pipe are illustrated in Figure 6. High tension and relatively small external pressure close to the surface of the sea, gradually increasing pressure and decreasing tension further down and high external pressure in the long suspended area and bending in the sagbend, and finally hydrostatic pressure on a seabed.

In addition, therefore, the possibility of accidentally initiating a propagation buckle cannot be overlooked, so installation of buckle arrestors is usually obligatory.

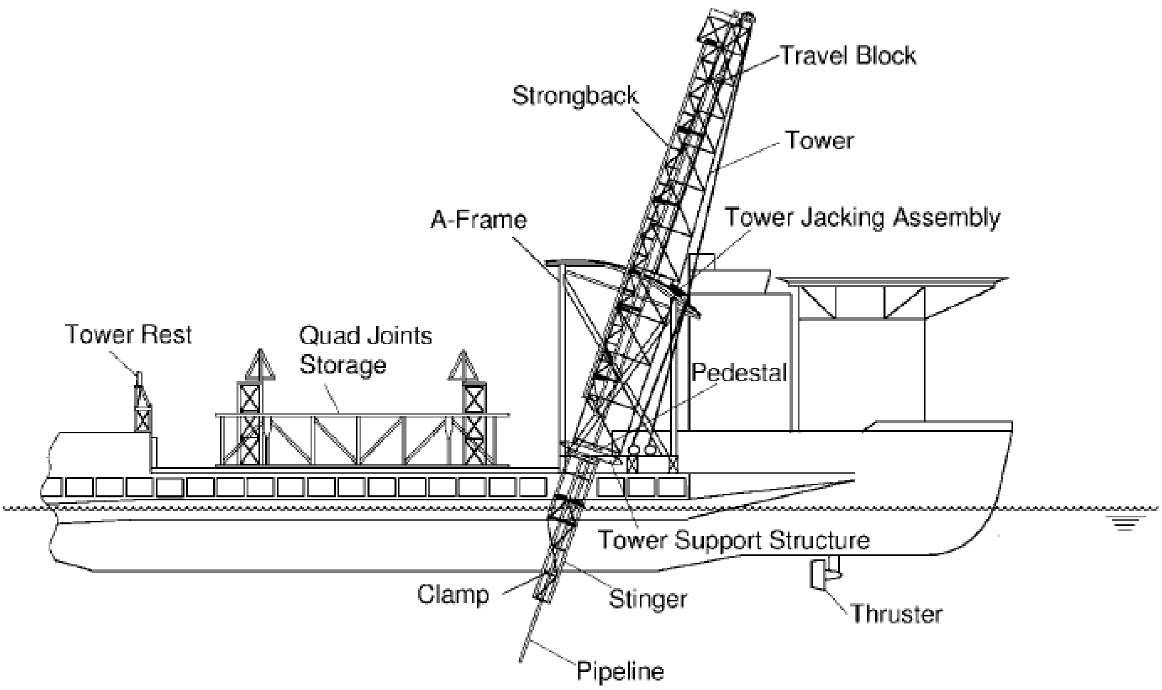

Figure 5.6 Derrick Barge [15]

Several additional J-Lay facilities have been developed since 1998. Two of the largest are Saipem S-7000 and Herema Balder [17]. Both are large semi-submersible crane vessels to which J-lay facilities were added. The S-7000 is one of the largest dynamically-positioned semi-submersible crane vessels in the industry which has removable J-lay tower (130m) on the deck (Figure 5.7).

Figure 5.7 the Saipem 7000 semi-submersible crane vessel [www.saipem.com]

The Balder is another large dynamically-positioned semi-submersible crane vessel converted in 2001 into a deepwater Construction Vessel by the addition of a J-lay tower [20]. The DCV Balder has been used to install the deepwater parts of the various pipelines and catenary risers in the Gulf of Mexico.

5.1.3 Reeling

In the Reel Vessel Method a section of pipe, usually several miles long, is wound onto a large diameter reel that is mounted onto a sea-going vessel while docked at a home base. The vessel travels to the installation site and installs the pipe by gradually reeling out the line. Existing reel vessels can lay pipes at speeds of up to two knots. The continuity of the method and transfer of most of the fabrication process on shore result in significant reductions in installation time and overall cost of such projects [14].

One of the examples of a reeling vessel is the Chickasaw barge, which has installed a lot of pipelines primarily in the Gulf of Mexico. The next major reeling technology development was Santa Fe's ship, named Apache equipped with a reel.
The reeling and unreeling processes induce bending curvatures of the pipe that are regulated in the plastic range of the material.

Thus the mechanical properties of the pipe must be designed such that local buckling is avoided. The probability of local buckling is reduced by applying some level of tension during both the winding and the unwinding of the pipe on the reel.

5.1.4 Towing

Another method of constructing and installing offshore pipelines is by towing them to the site. A section of pipeline is constructed onshore and it's then towed to the installation site using tug boats. An advantage of the technique is that welding, inspection and testing are conducted onshore before installation.

The design procedures for towed or pulled lines are very dependent on the type of tow method chosen. It is also important to control the submerged weight of a towed line to minimize towing forces and at the same time have sufficient weight for stability on the seabed in cross currents. In order to use the tow methods, the pipeline is normally constructed at an onshore site with access to the sea. Once the pipeline sections are welded together to a determined length, the pipe is de-watered and launched into the water by the tow vessel attached to the lead end [17].

Pipeline installation by towing can be divided into three main methods:
- Surface tow
- Controlled Depth Tow
- Off-Bottom Tow
- Bottom Tow

The choice of method is dependent on the following factors:
- Length of the pipeline
- The submerged weight of the pipeline
- The seabed conditions

In the surface tow and near surface tow methods, the pipeline is made buoyant by the periodic addition of buoys, so that it floats just below the surface of the sea. It is then towed out to location by a tugboat, while a trailing tug keeps the line taut (Figure 5.8). Once on location, the pipeline is lowered to the seabed by flooding the buoys in a controlled manner. Cross-currents and waves can be problematic, leading to fatigue and in some cases unstable oscillations of the trailing end [21]. Thus, this method is mainly implemented in shallow waters.

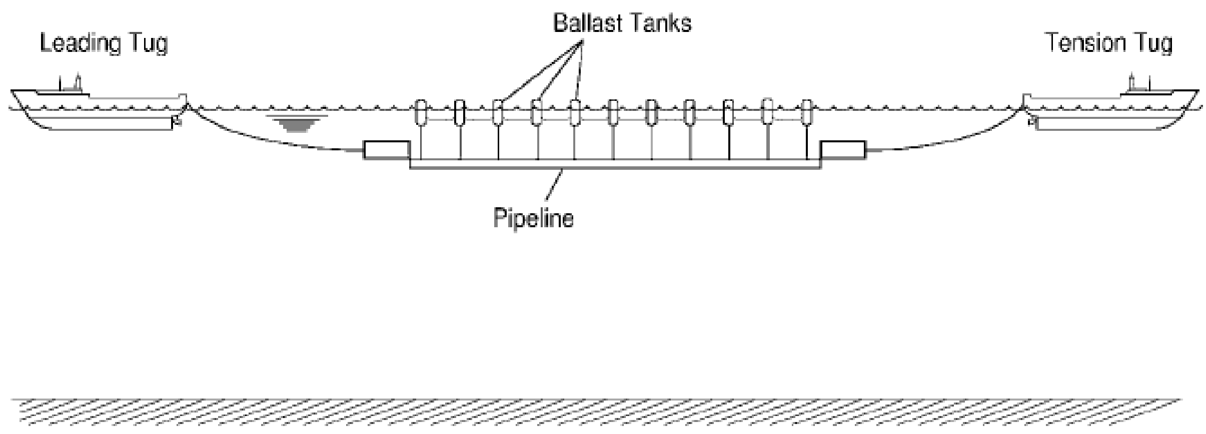

Figure 5.8 Tow installation method: surface tow [15]

In the controlled depth tow method, the pipeline is kept between two tug boats below the surface of the sea (Figure 5.9). In this method the effect of waves is reduced, though they still affect the tug boats and the line. The pipeline is usually buoyant, so it is weighted down by the addition of chains.

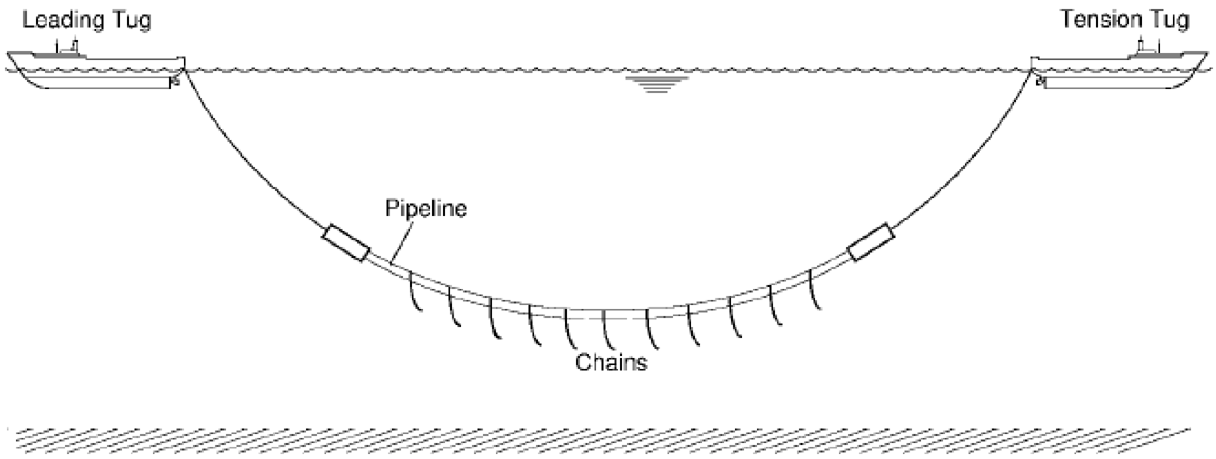

Figure 5.9 Controlled depth tow method [15]

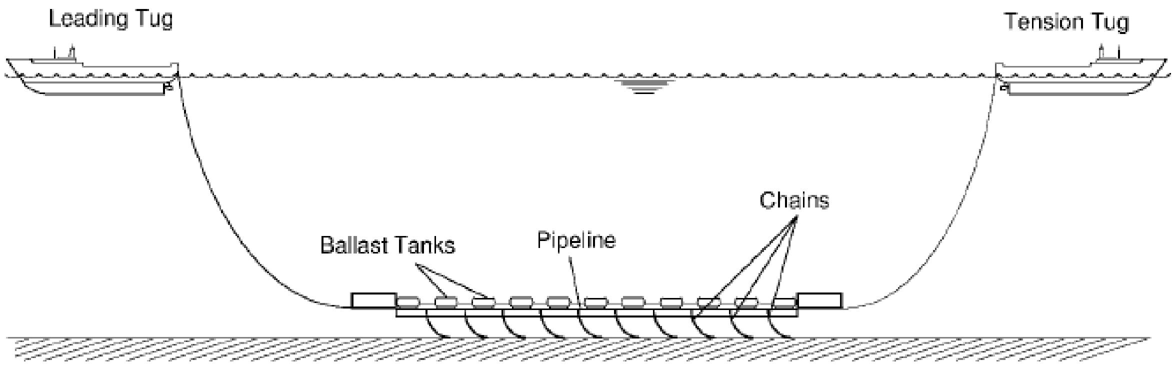

Figure 5.10 Off-bottom tow methods [15]

In the off-bottom tow method, the pipeline is weighted down by chains and is held by the tugboats just above the seabed (Figure 5.10). In this manner, the effects of surface waves and currents are reduced even further.

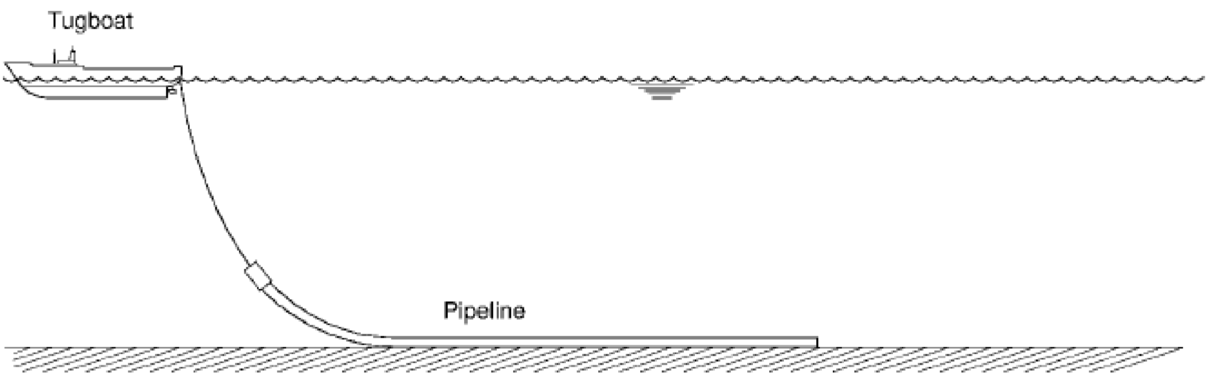

Figure 5.11 Bottom tow method [15]

In the bottom tow method, the pipeline is in contact with the seabed as shown in Figure 5.11 and a tugboat pulls it along the chosen route. In the case of heavier lines, pontoons can be added to reduce the frictional force that must be overcome.

In this method, the pipeline is less susceptible to currents and waves and concerns about fatigue, from which all of the towing methods suffer for some degree, are reduced. One must ensure, that the coating does not get damaged and that the route is free of obstacles that can damage the line [16].

5.1 Guidelines & Constraints for pipeline installation method

The operating environment for pipelines is notably different in shallow water and deepwater. Compared with shallow-water pipelines, pipelines located in deepwater endure:

- greater physical stresses (for example, extreme depths and strong currents) on the pipe and equipment during installation;
- higher hydrostatic pressures (that is, water pressure at depth); and
- colder water and sediment temperatures.

To date, approximately 54 percent of the deepwater fields have been developed using subsea completions. The produced hydrocarbon fluids are typically conveyed via multiphase (oil, gas, condensate, and water) flowlines and pipelines to a host facility.

Pipeline installation activities in deepwater areas can be difficult both in terms of route selection and construction. Depending on the location, the sea bottom surface can be extremely irregular and present engineering challenges (for example, high hydrostatic pressure, cold temperatures, and darkness, as well as varying subsurface current velocities and directions). Rugged seafloor may cause terrain-induced pressures within the pipe that can be operationally problematic, as the oil must be pumped up and down steep slopes.

An uneven seafloor could result in unacceptably long lengths of unsupported pipeline, referred to as “spanning,” which in turn could lead to pipe failure from bending stress early in the life of the line. It is important to identify areas where significant lengths of pipeline may go unsupported.

Accurate, high-resolution geophysical surveying becomes increasingly important in areas with irregular seafloor. Recent advances in surveying techniques have significantly improved the capabilities for accurately defining seafloor conditions, providing the resolution needed to determine areas where pipeline spans may occur [27]. After analyzing survey data, the operator chooses a route that minimizes pipeline length and avoids areas of seafloor geologic structures and obstructions that might cause excessive pipe spanning, unstable seafloor, and potential benthic communities.

Chapter 6 - Flexible risers and umbilical installation methods [23]

6.1 Methods for umbilical installation

We will here discuss methods for umbilical installation:

- Lowering a riser or umbilical over a stern chute
- Lowering a riser or umbilical through a moonpool
- Transfer of a riser/umbilical from an installation vessel to a floating platform
- Lowering a subsea package

6.1.1 Lowering a riser or umbilical over a stern chute

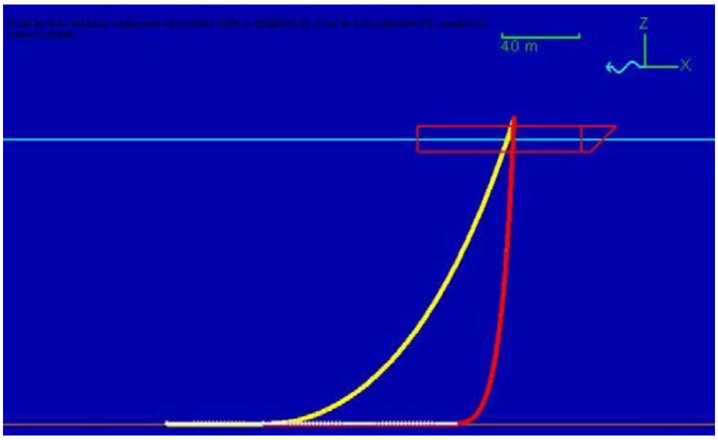

Figure 6.1 Sample for Lowering a riser or umbilical over a stern chute [23]

Advantages: Simplicity, Vessel availability
Problems: Pitch-heave coupling, compression, vessel holding capacity
Riser limits: Tension, curvature, compression

6.1.2 Lowering a riser or umbilical through a moonpool

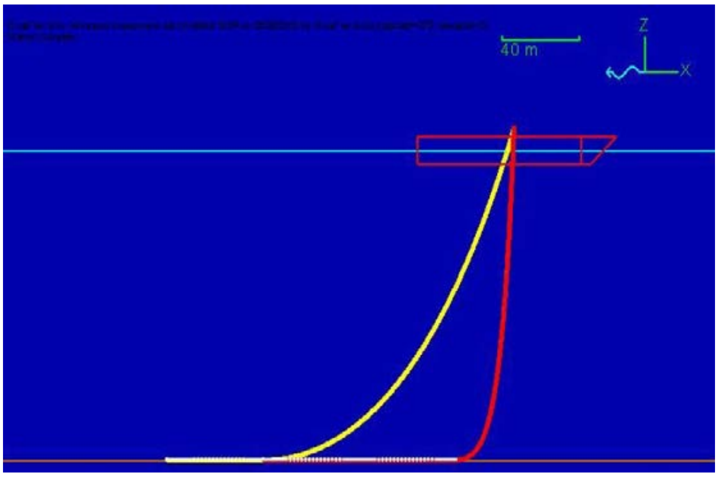

Figure 6.2 Sample for Lowering a riser or umbilical through a moonpool [23]

Advantages: Lower top end motions
Disadvantages: Reduced vessel availability and therefore higher cost

6.1.3 Transfer of an umbilical from an installation vessel to a floating platform

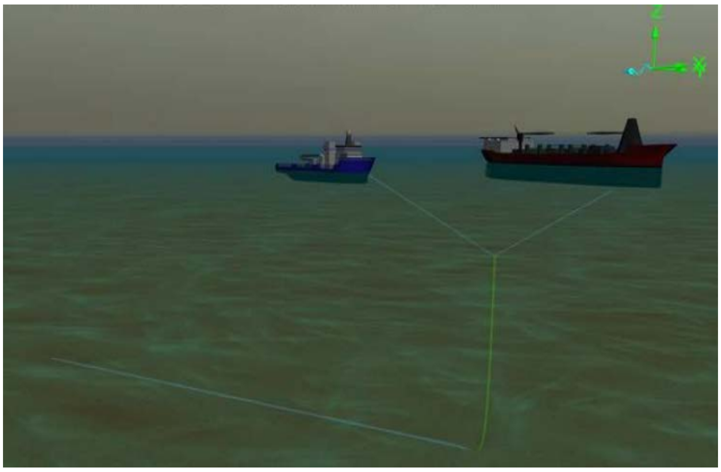

Figure 6.3 Sample for transfer of an umbilical from an installation vessel to a floating platform [23]

Issues: winch capacity, contact with vessel hulls, tension and curvature in riser, compression at touchdown
For I-tube pull-in: friction loads, possibility of pull head jamming

6.1.4 Lowering a subsea package

For example: manifold, template, line end terminations, any heavy equipment

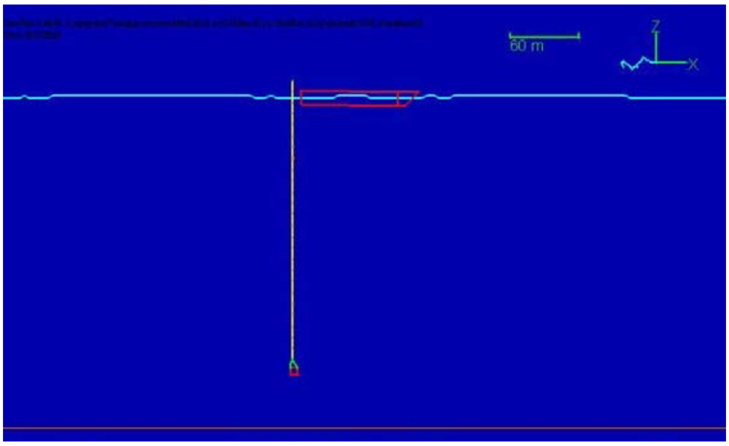

Figure 6.4 Sample for Lowering a subsea package [23]

Concerns:

- Lowering: resonance effects, slack rigging.
  (Mitigation: Heave compensation devices, irregular wave analysis)
- Touchdown: excessive motion, contact loads
  (Mitigation: Heave compensation devices, additional buoyancy to slow fall)
- Splash zone: slamming loads, slack rigging
  (Mitigation: use vessel as a shield, lower fairly quickly)

5.2 Guidelines & Constraints for flexible risers and umbilical installation method

The following should be considered when establishing the installation method / scenario: [25]

- Schedule constraints:
  - ✓ Infra-structure (FPSO, subsea structure, platform) presence,
  - ✓ Client's requirement (wet storage in order to minimize influence of installation activities on 'first oil' critical path),
  - ✓ Internal requirements (asset availability),
  - ✓ Minimize diver intervention time

- Permanent works design limitations:
  - ✓ Loads imposed on permanent works and associated installation aids (tension, bending moment, crushing in tensioner),
  - ✓ Bend stiffener latching system's capability to cope with misalignment entry angle,
  - ✓ Packing (termination size may impose a laying direction) [25].

- Asset's capacity:
  - ✓ Loads imposed on vessel (horizontal loads on vessel vs station keeping capability)[26],
  - ✓ Loads imposed on lay equipment (tensioners, pulling winches,…), Height above hook (transfer from tensioner to crane or Abandonment and Recover- A&R winch),
  - ✓ Deck handling[14].

- Subsea operations:
  - ✓ A vertical connector is normally deployed open to sea (therefore increasing top tension as it is lowered first end),
  - ✓ It is preferable to deploy a vertical connector as 1st end (torsion issue leading to connector not facing down),
  - ✓ If a termination has an imposed orientation on seabed (e.g. termination with a mudmat, vertical connector), it is preferable to deploy it 1st end because orientation can be better controlled.

- Clearance/clashes/congestion

- Pre-commissioning constraints

It is obvious that there is a lot to be looked at!!!

Chapter 7 – Orcaflex

7.1 General description about software Orcaflex

(Taken from Introduction chapter in OrcaFlex Manual Version 9.5a by Orcina) [28].

OrcaFlex is a marine dynamics program developed by Orcina for static and dynamic analysis of a wide range of offshore systems, including all types of marine risers (rigid and flexible), global analysis, moorings, installation and towed systems.

OrcaFlex provides accurate analysis of catenary systems such as flexible risers and umbilical cables under wave and current loads and externally imposed motions. OrcaFlex makes extensive use of graphics to assist understanding. The program can be operated in batch mode for routine analysis work and there are also special facilities for post-processing the results including fully integrated fatigue analysis capabilities.

OrcaFlex is a fully 3D non-linear time domain finite element program capable of dealing with arbitrarily large deflections of the flexible from the initial configu-ration. A lumped mass element is used which greatly simplifies the mathematical formulation and allows quick and efficient development of the program to include additional force terms and constraints on the system in response to new engineering requirements.

In addition to the time domain features, modal analysis can be performed for individual lines and Response Amplitude Operators (RAOs) can be calculated for any resulting variable using the Spectral Response Analysis feature.

OrcaFlex is fully 3D and can handle multi-line systems, floating lines, and line dynamics after release, etc. Inputs include ship motions, regular and random waves.

7.2 Orcaflex Coordinate System

Orcaflex uses one global coordinate system (GXYZ) and a number of local coordinate systems (Lxyz), generally one for each object in the model. The coordinate system used in Orcaflex is shown in Figure 7.1. Most of the data and results are given relative to the global axes, including the positions of objects, current and wave directions.

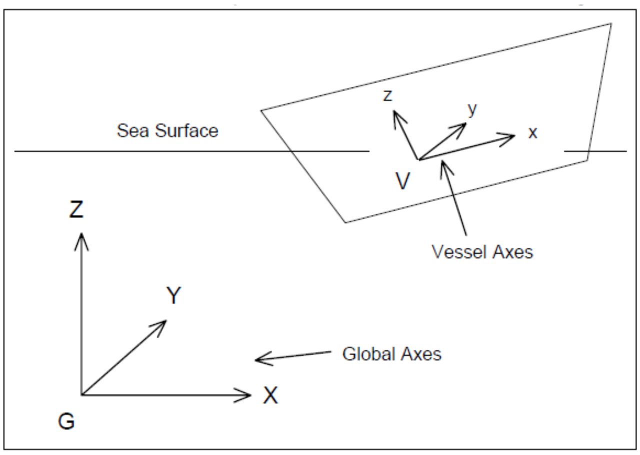

Figure 7.1 Orcaflex's Coordinate Systems [28]

Orcaflex specifies directions and headings by giving the azimuth angle of the direction, in degrees, measured positive from the x-axis towards the y-axis, as shown in Figure 7.2.

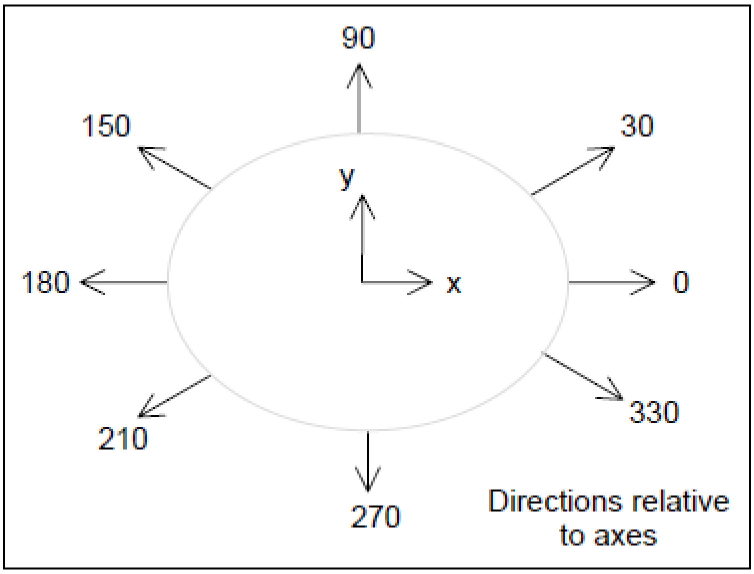

Figure 7.2 Orcaflex's Direction and Headings [28]

Directions are defined in OrcaFlex by giving two angles, azimuth and declination which are sometimes defined relative to the global axes and sometimes relative to the local object axes.

For directions defined relative to the local object axes, the azimuth and declination angles are defined as follows:

- Azimuth is the angle from the x axis to the projection of the direction onto the xy plane (Azimuth is 0° for the positive x axis direction and 90° for the positive y axis direction).
- Declination is the angle the direction makes with the z axis. Therefore Declination is 0° for the positive z-direction, 90° for any direction in the xy plane, and 180° for the negative z-direction.

7.3 Static and Dynamic stage

7.3.1 Static analysis

There are two objectives for a static analysis:

- To determine the equilibrium configuration of the system under weight, buoyancy, hydrodynamic drags, etc.
- To provide a starting configuration for dynamic simulation.

Orcaflex determines the static equilibrium position by a series of iterative stages:

1. At the start of the calculation, the initial positions of the vessels and buoys are defined by the data: these in turn define the initial positions of the ends of any lines connected to them.
2. The equilibrium configuration for each line is then calculated; assuming the line ends are fixed.

3. The out of balance load acting on each free body (node, buoy, etc.) is then calculated and a new position for the body is estimated. The process is repeated until the out of balance load on each free body is zero (up to the specified tolerance). For details see Statics of Buoys and Vessels.

7.3.2 Dynamic analysis

The dynamic analysis is a time simulation of the motions of the model over a specified period of time, starting from the position derived by the static analysis.

Before the main simulation stage(s) there is a build-up stage, during which the wave and vessel motions are smoothly ramped up from zero to their full size. This build-up stage is numbered 0 and its length should normally be set to at least one wave period. Figure 7.3 shows the time and simulation stages in Dynamic analysis of Orcaflex.

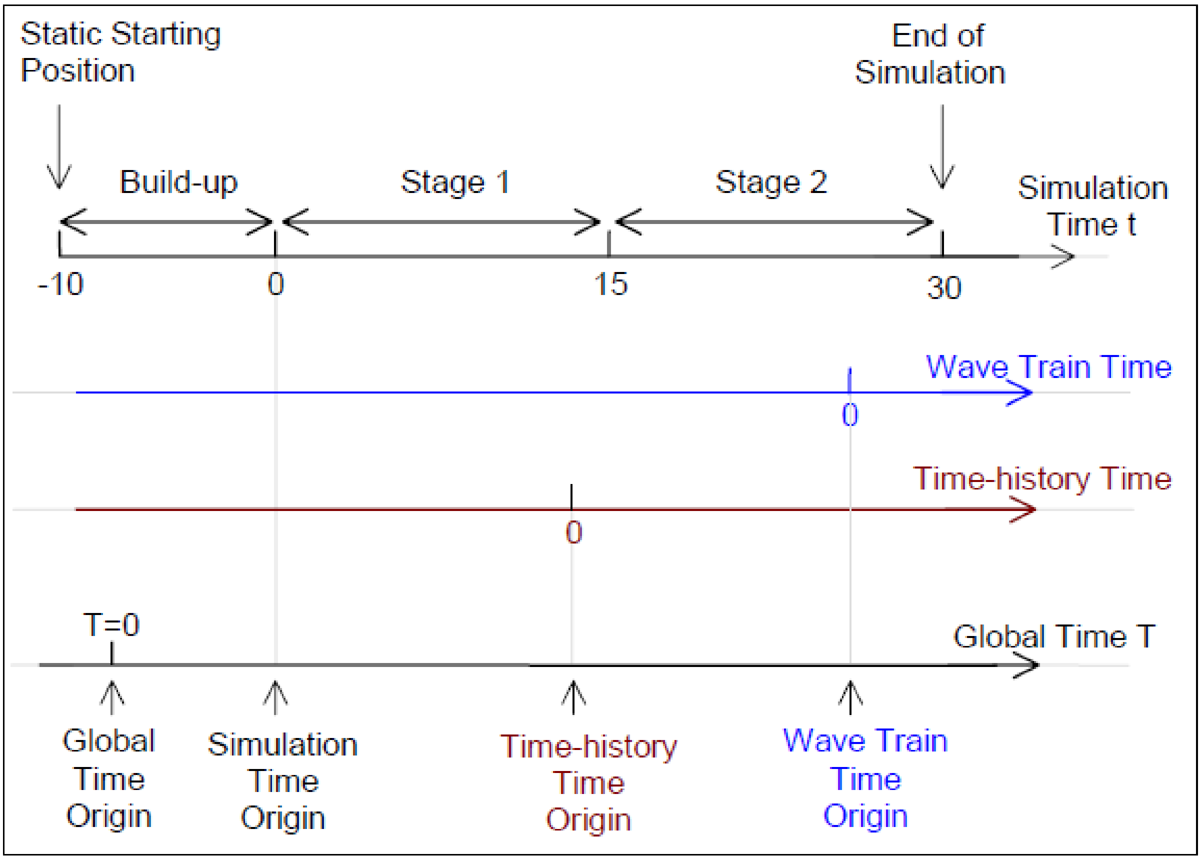

Figure 7.3 Orcaflex's Time Simulation and Stages in dynamic analysis [28]

OrcaFlex implements two complementary dynamic integration schemes which are the Explicit and the Implicit schemes. The explicit scheme is using a forward Euler method with constant time step. At the start of the time simulation, the initial positions and orientations of all objects in the model are known from the static analysis.

The forces and moments acting on each free body and nodes are then calculated using the equation of motion of the Newton's law. This equation is then solved for the acceleration vector at the beginning of the time step, for each free body and each line node. The next step is to integrate the acceleration vectors using forward Euler integration. At the end of each time step, the positions and orientations of all nodes and free bodies are gain known and the same process is repeated.

The implicit integration scheme is applied in Orcaflex using the Generated- α integration scheme. The forces, moments, damping, mass, etc. are calculated using the same procedure as in the explicit scheme. The difference is that the system equation of motion is solved at the end of the time in the implicit scheme. Because the parameters are unknown at the end of the time step, hence an iterative solution method is required [30]. Consequently, each implicit time step consumes significantly more computation time than an explicit time step. However, the implicit scheme is typically stable for much longer time steps than the explicit scheme and often this means that the implicit scheme is faster.

7.4 Modeling in Orcaflex

Making a model in Orcaflex is done by placing default shaped objects on the screen [29]. There are several available objects from Orcaflex library to be included in the model, such as: Vessel, Line, 6 Dimensional Buoy, 3 Dimensional Buoy, Link and Winch [30]. 6 Dimensional Buoy means that the object has six degrees of freedom and is given hydrodynamic properties as drag, added mass and damping for all directions.

The geometry of the object can be changed; even though this has no relation to the hydrodynamic properties of the object. Hydrodynamic properties are defined from manually input data for each of the objects. Vessel properties are also defined using a quite similar method. RAO data for specific vessel is imported from other sources, for example the MOSES program. Initial conditions such as trim angle, draught and heading are then applied to the vessel as part of the vessel inputs.

Chapter 8 – Case analysis
Installation of steel pipelines and flexible pipeline in sideway current

8.1 Introduction

S-lay is the most common method for subsea pipeline installation. The application of this method has been proven not just in shallow water but also in deepwater. The first deepwater exploration for oil and gas in Indonesia was done in Makassar Strait in early 2000. Makassar Strait is well known for its strong current condition [57], [58] as the strait is like a passage between the Pacific Ocean and the Indian Ocean (Figure 8.1). When a pipeline needs to be installed in an area with strong currents such as the Makassar Strait, it will be subject to current load. The stronger the current the higher the load will be. And this will result in increase of the stress in pipeline during the pipe-lay activity.

Figure 8.1 the Makassar Strait [31]

The ocean current speed varies all over the world. Field current measurements have been done extensively everywhere and are still going on nowadays. In Makassar Strait in Indonesia, where the country's first deepwater exploration West Seno field was approved back in 1999 [31] current data gathering for research purpose has been conducted since early 90's through projects such as Arlindo project ("Arlindo" is an acronym for Arus Lintas Indonen, meaning 'throughflow' in Bahasa Indonesia, is a joint oceanographic research endeavor of Indonesia and the United States.[59]), INSTANT (The International Nusantara Stratification and Transport [60]) program, and from some other international research projects. At some locations in the world, like the Makassar Strait, the current can be very strong and this will give significant current loads to underwater structures such as subsea pipelines which cannot be neglected anymore.

When doing an analysis of subsea pipeline installation with the conventional lay barge method there are two regions that need to be carefully looked after as they most of the time are the critical locations where stresses are high. They are called the “overbend” and the “sagbend” regions (Figure 8.2).

In these regions the pipe will suffer from bending stress as well as axial stress and hydrostatic pressure due to the nature of the curvature profile. The curvature radius can be defined as desired by applying proper tension to the pipe and also by controlling the stinger profile. If there is strong current flowing in the environment, the predefined pipe curvature radius will be affected and the stresses in the pipe can be severely increased due to implementation of significant current loads to the unsupported span of the pipeline depending on the direction of the current.

It should also be noted that the stresses at the end of the stinger could be very high in case of large motions of the lay barge

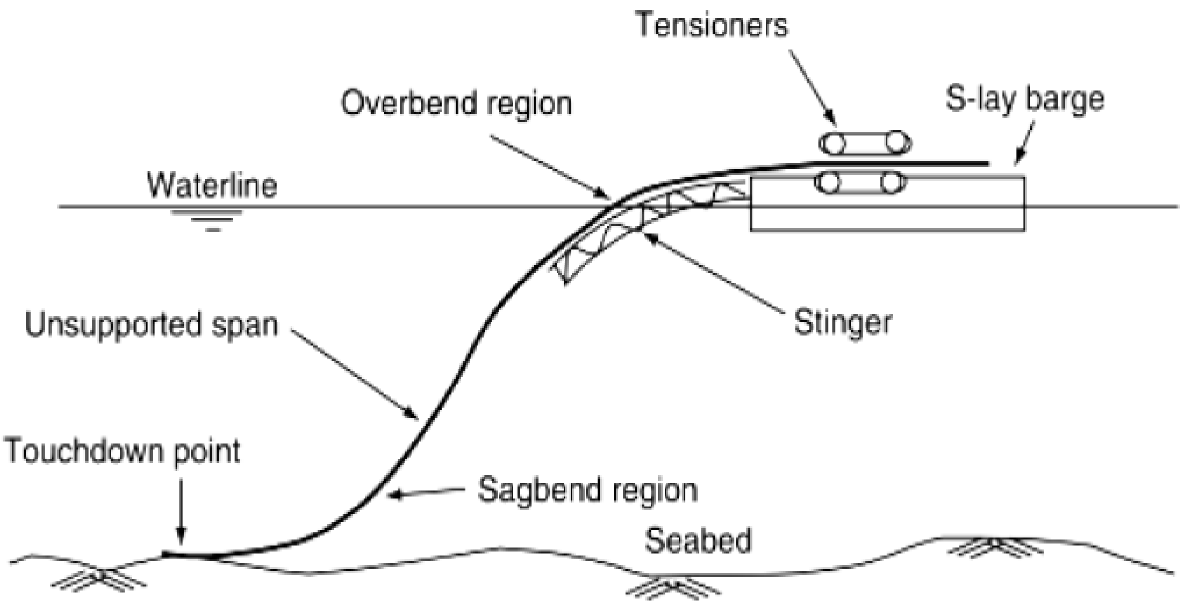

Figure 8.2 S-lay configurations [32]

It will attempt to discuss this strong current effect by analysis using OrcaFlex software. The objective is to give a general overview about how the stresses in the pipe will change when current load from a particular direction is applied to the pipeline during the pipe-lay activity.

8.2 Makassar Strait Current Speed Data

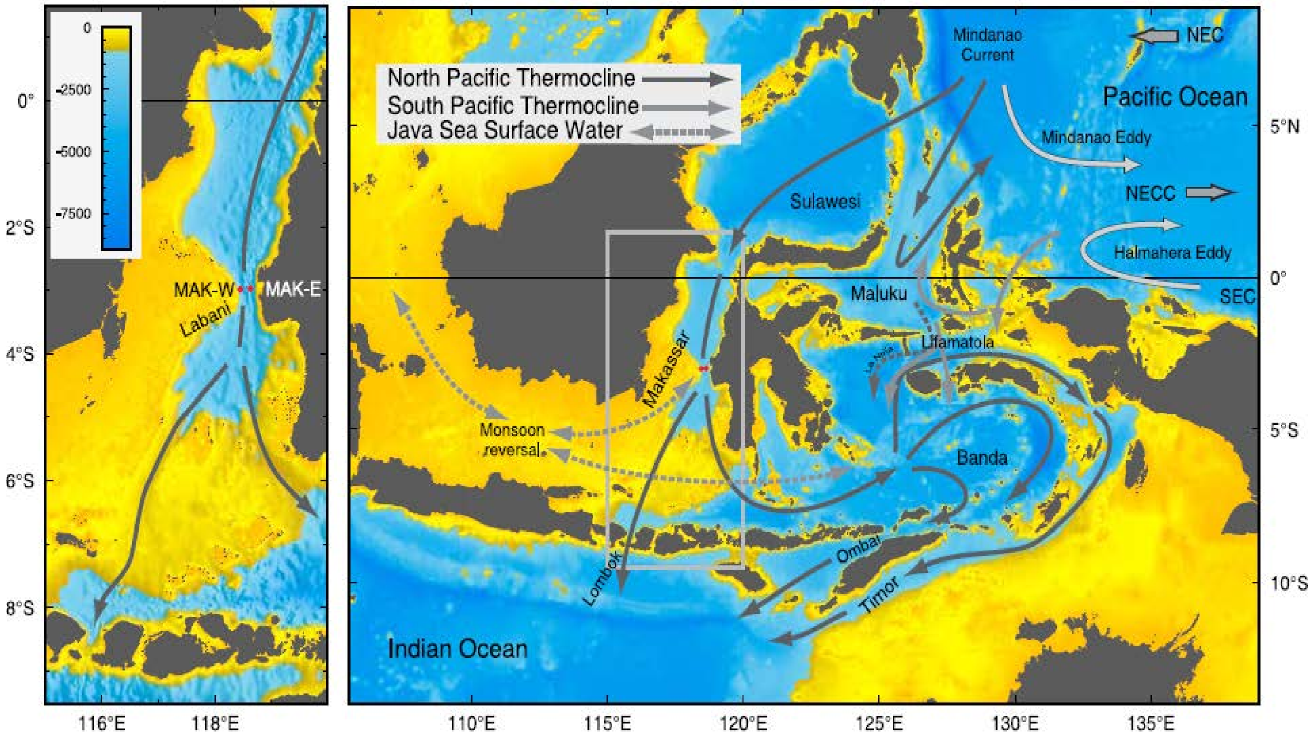

Figure 8.3 (left) expanded view of the Makassar Strait region {the solid grey lines mark the approximate pathway of the Makassar throughflow}. (right) Schematic of the Indonesian throughflow pattern {the grey box delineates the expanded view shown on the left}. [33]

Makassar Strait throughflow has recently become once again a subject for research by deploying moorings with instruments such as ADCP (Acoustic Doppler Current Profilers) attached, to measure the current velocity around Labani channel area (Figure 8.3). The research was conducted mainly to examine the transport of water from the Pacific Ocean to the Indian Ocean [33].

An Acoustic Doppler Current Profiler (ADCP or ADP) is sonar that attempts to produce a record of water current velocities for a range of depths. The profiler are made of ceramic materials, and contain transducers (Figure 8.4), an amplifier, a receiver, a mixer, an oscillator, a clock, a temperature sensor, a compass, a pitch and roll sensor, and computer components to save the information collected.

Figure 8.4 Head of an ADCP with the four transducers [34]

ADCPs can be configured in many ways: side-listening, into rivers and canals for long term continuous discharge measurements, downward-listening and mounted on boats for instantaneous during surveys in the ocean or in rivers, and mounted on moorings, or the seabed for long term current & wave studies. They can stay underwater for years at a time, and have a battery pack for an energy source. The sonar is used for oceanography, estuary, river and stream flow measurements, and weather forecasting [34].

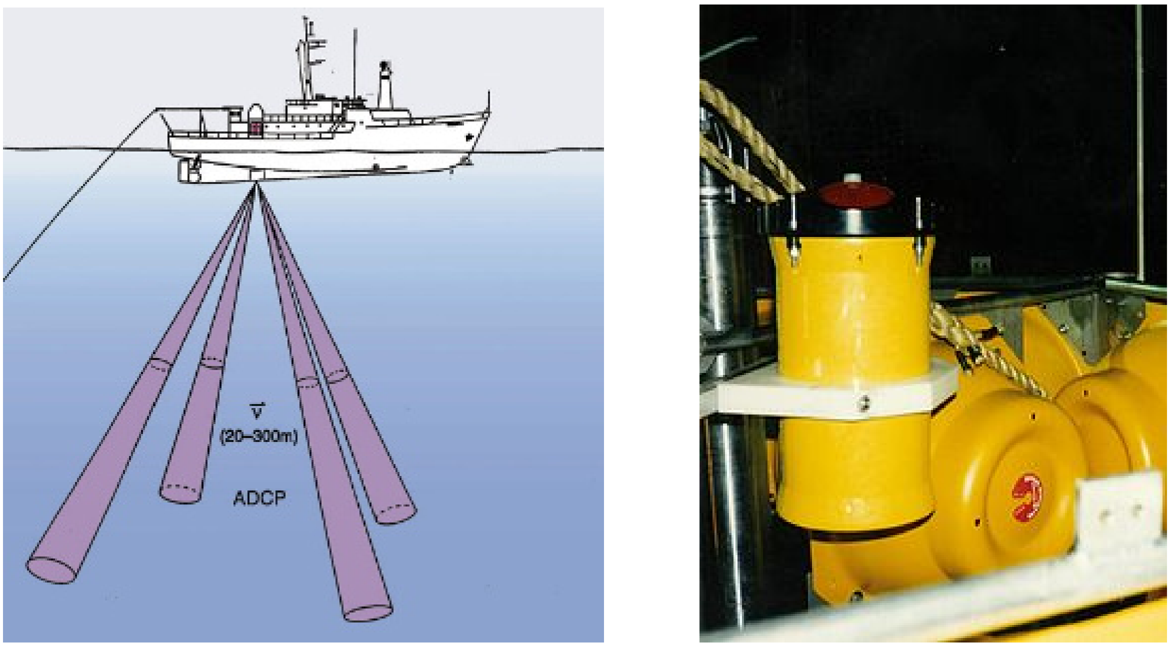

Figure 8.5 ADCP view ahead, mounted on an oceanographic device for long term measurements in the deep sea [34]

The along channel average speed profile was extracted from the records of two moorings and can be seen in Table 8.1 below:

Table 8.1 Record of average speed and directions at various depths -Direction is measured clockwise from north direction [33]

Mooring	Depth (m)	Speed (m/s)	Direction (°)
MAK-West	40	0,43	161
	140	0,67	157
	280	0,45	154
	400	0,22	151
	750	0,02	173
(below sill depth)	1500	0,01	-6
MAK-East	40	0,40	164
	140	0,55	166
	280	0,32	165
	400	0,16	164
(below sill depth)	750	0,03	179

8.3 Case description

One S-lay pipeline installation case will be taken for analysis in this thesis.

In this model, the stingers elements are modeled as points which are held by links/tethers in both vertical and lateral directions. The links are restricted only to accept tension force without any shear forces or bending moments. The idea is that these links will act as “roller” restraints.

Tension in a vertical link will represent a stinger roller reaction when the pipe is sitting on the roller, and zero force will represent a pipe lift-off. Same criteria apply to the lateral links. Tension in a lateral link will represent a lateral reaction which is due to lateral forces on the pipe. These lateral links are simple but very useful components for the model to reach its equilibrium during iterations.

The upper end of the pipeline is fixed to the barge and will not accept torsion. This end represents the barge tensioner. The bottom end of the pipeline is pinned to the seabed with no torsion allowed and will represent an anchored end.

There is one thing to be remembered in this modeling technique. Each stinger roller relative coordinate will remain constant with respect to the barge. This means the contact area between the pipe and each roller will always be the same. However, it will still represent a pipe-lay profile model properly. Some graphical representations of the model are presented in Figures 8.6 to 8.8.

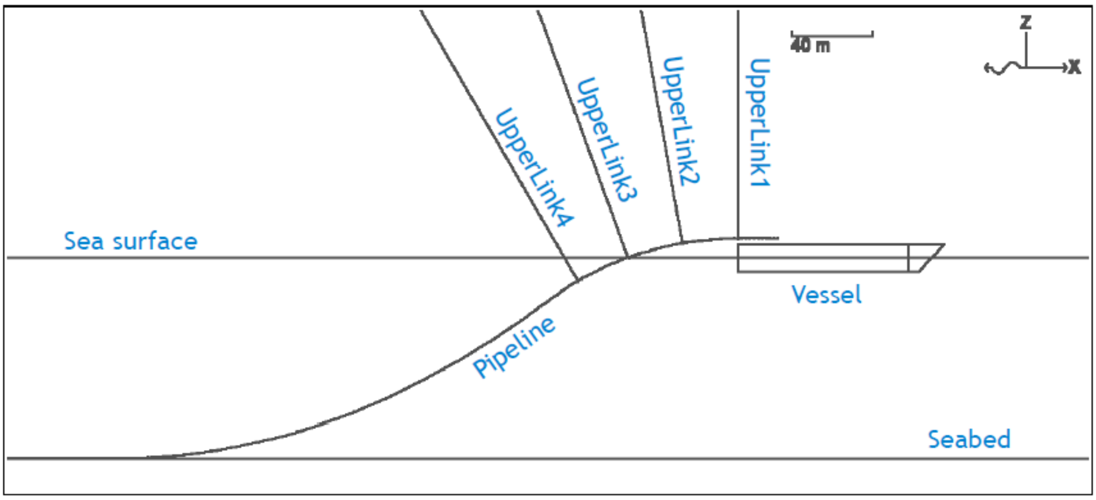

Figure 8.6 Model global xz-plane view

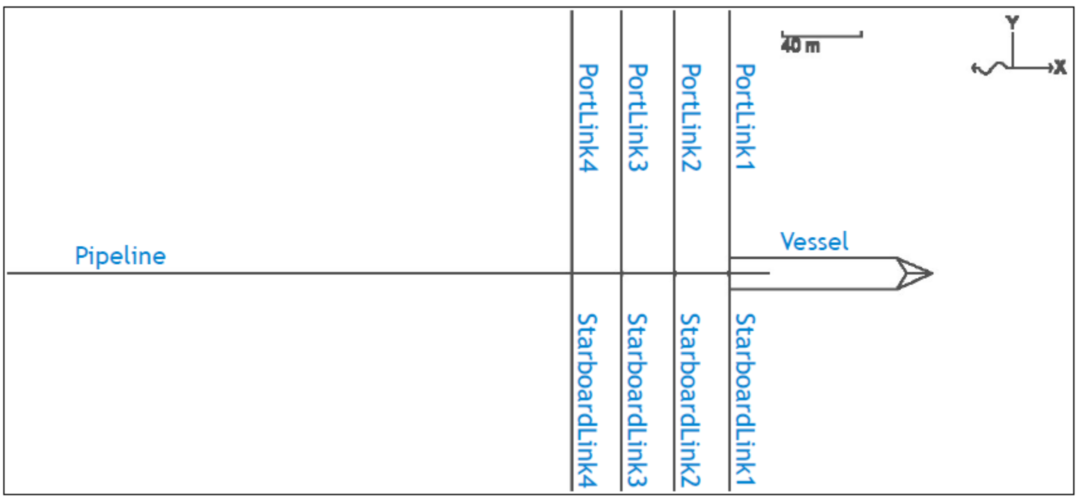

Figure 8.7 Model global xy-plane view

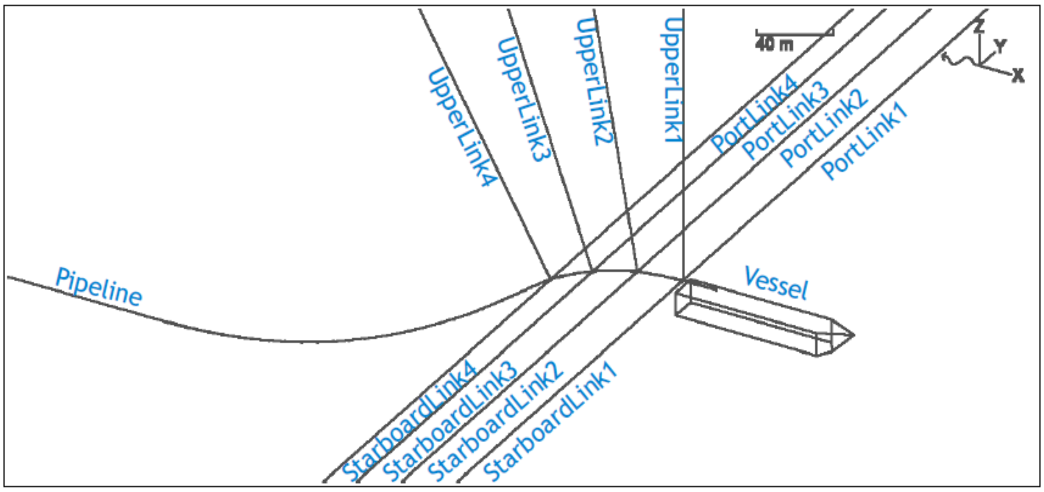

Figure 8.8 Model global xyz-plane view

8.4 Theoretical Background: Stress Theory and Allowables

8.4.1 Circumferential stress due to pressure

Hydrostatic pressure gives big contributions to the stress in the pipeline during pipe-lay. The stress resulting from this pressure (as well as the internal pressure) is called circumferential/hoop stress. The fundamental of this stress can be derived simply from the following illustration (Figure 8.9)

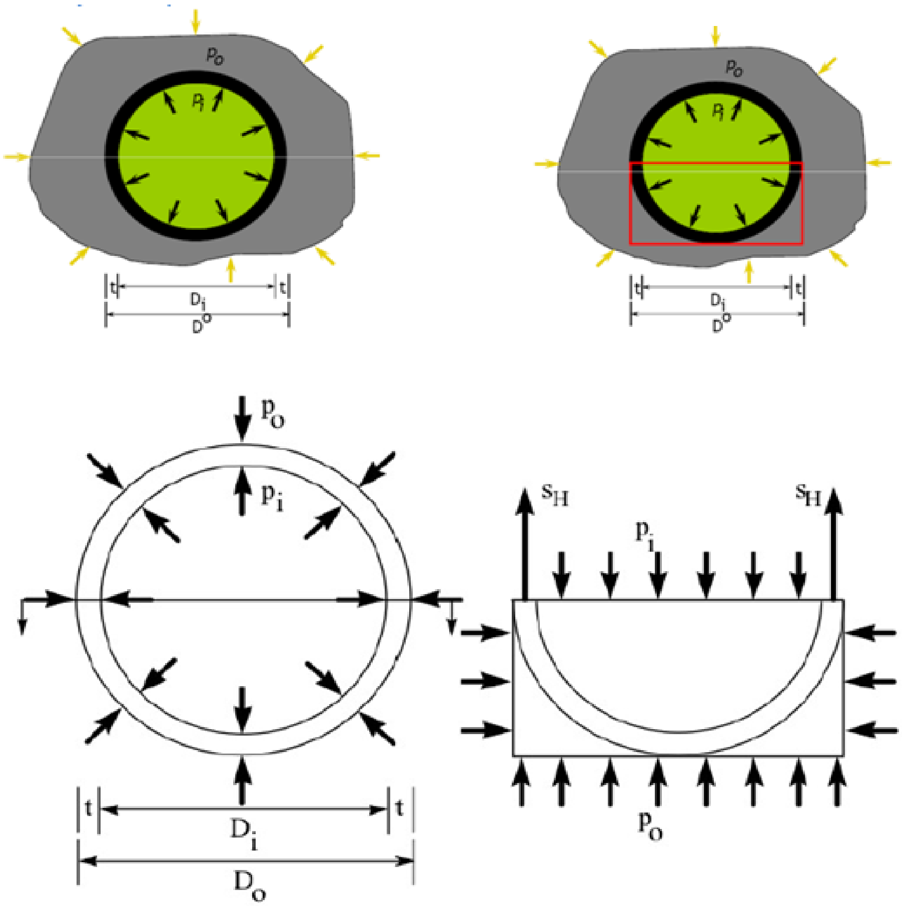

Figure 8.9 Circumferential stresses in a pipeline [35]

The summation of forces in horizontal direction is zero due to symmetry; the pressure components to the left and right will eliminate each other. In the vertical direction, the summation of forces (per unit length) can be written as: [35]

$$0 = p_o \cdot D_o + 2 \cdot S_H \cdot t - p_i \cdot D_i$$

$$S_H = \frac{p_i \cdot D_i - p_o \cdot D_o}{2 \cdot t}$$

Where S_H = circumferential/hoop stress
p_o, p_i = external and internal pressures, respectively
D_o, D_i = external and internal pipe diameters, respectively
t = pipe wall thickness

8.4.2 Bending stress

Assumptions for pure bending stress in a beam are that plane cross sections remain plane and remain normal to the longitudinal fiber after bending, and also the beam is made from linearly elastic material (Hooke's Law) and homogenous [36].

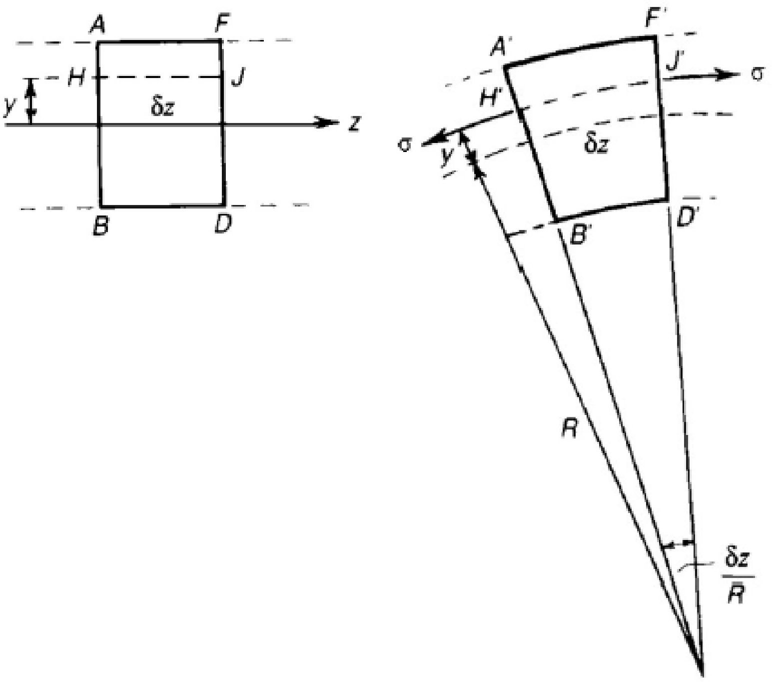

Figure 8.10 Bent element of a beam [36]

From Figure 8.10 above, with beam width b and depth h, it can be derived:

$$\frac{H'J'}{\delta z} = \frac{R+y}{R}$$

Strain $\varepsilon = \frac{H'J' - HJ}{HJ} = \frac{R+y}{R} - 1 = \frac{y}{R}$

Stress $\sigma = E \cdot \varepsilon = \frac{E \cdot y}{R}$

Moment $$M = \int_{-\frac{h}{2}}^{\frac{h}{2}} \sigma\, y\, b\, dy = \frac{E}{R}\int_{-\frac{h}{2}}^{\frac{h}{2}} y^2\, b\, dy = \frac{E}{R}\frac{b\,h^3}{12} = \frac{E\,I}{R}$$

$$\frac{\sigma}{y} = \frac{E}{R} = \frac{M}{I}$$

Where E= Young's modulus
I = moment of inertia

8.4.3 Orcaflex equivalent stress

This section refers to Orcaflex Manual [28].

OrcaFlex reports two different types of tension - the effective tension (T_e) and the wall tension (T_w). These two tensions are related by the formula:

$$T_w = C1\,(T_e + P_i\,A_i - P_o\,A_o)$$

Where p_i, p_o= internal and external pressures, respectively
A_i, A_o = internal and external cross section areas of the stress annulus
C1 = tensile stress loading factor. By default this equals 1.

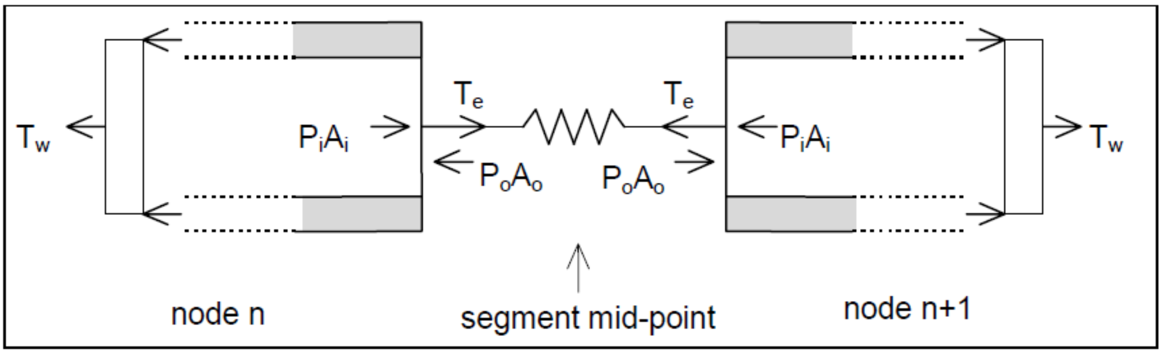

Figure 8.11 OrcaFlex effective tensions and wall tension diagram [28]

To understand more consider the forces acting axially at the mid-point of a segment (Figure 8.11). The nodes at either side represent a length of pipe plus its contents. More importantly, the forces on them are calculated as if the length of the pipe represented had end caps which hold the contents and which are exposed to the internal and external pressure. The diagram above (Figure 8.11) illustrates this and shows the tension and pressure forces present; the equation above is simply the force balance equation for this diagram.

Von Mises stress is a value that is most commonly used as a yield criterion. In terms of principal stresses σe, OrcaFlex calculates this as:

$$\sigma_e = \sqrt{\frac{1}{2}[(\sigma_1-\sigma_2)^2+(\sigma_2-\sigma_3)^2+(\sigma_3-\sigma_1)^2]}$$

Where σ_e = equivalent stress (Von Mises) [37]
σ_1, σ_2, σ_3 = principal stresses (Figure 8.12)

From elasticity theory, an infinitesimal volume of material at an arbitrary point on or the inside of the solid body can be rotated such that only normal stresses remain and all shear stresses are zero. The three normal stresses that remain are called the principal stresses:

σ_1 - Maximum

σ_2 - Middle

σ_3 - Minimum

The principal stresses are always ordered such that $\sigma_1 > \sigma_2 > \sigma_3$. [38]

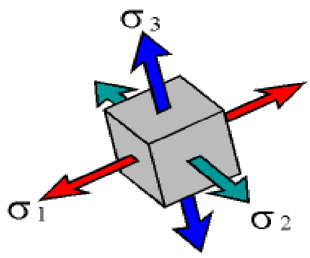

Figure 8.12 principal stresses [38]

Consider a cross-section through a mid-segment point, as shown in the following diagram (Figure 8.13). The diagram shows the frame of reference used for the cross-section, which has origin O is at the pipe centerline, Oz along the pipe axis (positive towards End B) and Ox and Oy normal to the pipe axis (and so in the plane of the cross-section) [28].

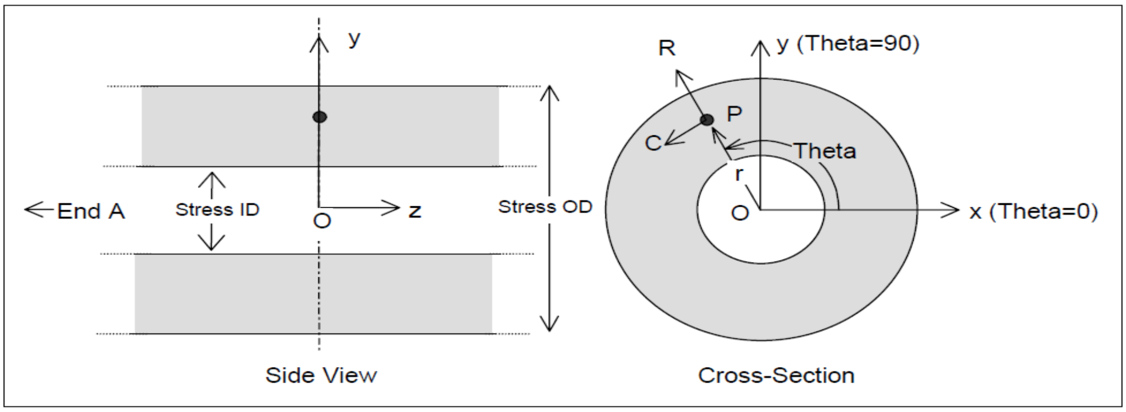

Figure 8.13 OrcaFlex reference for stress calculation [28]

The principal stresses are the three roots of stress component matrix. Orcaflex stress component matrix is: $\begin{pmatrix} RR & RC & RZ \\ RC & CC & CZ \\ RZ & CZ & ZZ \end{pmatrix}$

Diagonal shear stresses:

$$RR = \text{radial stress} = A-\frac{B}{r^2} = \frac{p_1a^2-p_2b^2}{b^2-a^2}-\frac{a^2b^2(p_1-p_2)}{(b^2-a^2)r^2}$$

$$CC = \text{hoop stress} = A+\frac{B}{r^2} = \frac{p_1a^2-p_2b^2}{b^2-a^2}+\frac{a^2b^2(p_1-p_2)}{(b^2-a^2)r^2}$$

$$ZZ = \text{axial stress} = \sigma_r+\sigma_b$$

Where

r, θ= point location in angular coordinate
p_1, p_2= internal and external pressure, respectively
a, b = inner and outer pipe radius, respectively
σ_t= direct tensile stress = T_w / A_z
σ_b= bending stress = $\{r \times (M_x \sin\theta - M_y \cos\theta)\} / I_{xy}$
T_w= wall tension
A_z= cross section area
M_x, M_y= bending moment components about x and y axis
I_{xy}= moment of inertia about x or y axis

And the off-diagonal shear stresses:

$$RC = 0$$

$$RZ = \frac{S_x \cos\theta + S_y \sin\theta}{A_z}$$

$$CZ = \frac{S_y \cos(\theta) - S_x \sin(\theta)}{A_z} + \sigma_\tau$$

Where

S_x, S_y= shear force components in xy plane
σ_τ= shear stress due to torque = $\tau r / I_z$
τ= torsion
I_z= moment of inertia about z axis = $2\, I_{xy}$

So that the determinant satisfies:

$$\begin{vmatrix} RR-\sigma & RC & RZ \\ RC & CC-\sigma & CZ \\ RZ & CZ & ZZ-\sigma \end{vmatrix} = 0$$

8.4.4 DNV equivalent stress

DNV (working stress design) uses a different approach to calculate Von Mises stress. According to this offshore standard, the stress shall be calculated as:

$$\sigma_e = \sqrt{\sigma_h^2 + \sigma_l^2 - \sigma_h \times \sigma_l}$$

With

$$\sigma_h = (p_1 - p_2)\frac{D}{2t}$$

$$\sigma_l = \text{axial stress + bending stress} = \frac{N}{A_z} + \frac{M}{W}$$

Where

σ_h = hoop stress
σ_l = longitudinal stress (including effect of water pressure)
D = pipe diameter
T = wall thickness
N = true pipe wall force
M = bending moment
W = pipe section modulus

To be noticed that during installation the internal pressure of the pipeline is zero because of empty pipe and the external pressure is simply the hydrostatic pressure which increases as the pipe goes deeper into the sea. Comparison between Von Mises stresses based on Orcaflex and DNV will be conducted for general study and can be found in Appendix A.

All allowable and/or usage factors will not be included into the calculations.

8.4.5 Allowable stress

According to DNV (working stress design), the following yield criterion shall be used as the allowable stress in pipeline:

$$\sigma_e \leq \eta_{ep} \sigma_F \cdot k_t$$

Where

η_{ep}= usage factor = 0.96 for condition including environmental load, or
0.72 for condition without environmental load
σ_F= specific minimum yield strength (SMYS)
k_t= temperature derating factor = 1.0 for material temperature <120^{o}C

Chapter 9 – Case 1

Installation of steel pipelines in sideway current

9.1 Case properties

The properties of the steel pipe chosen for this example case with the current speed based on the Makassar Strait current data (from Section 8.2) can be seen in Table 9.1 below:

Table 9.1 Properties for pipelay case 1

Pipe dimension	250mm OD × 15 mm WT steel pipe
Pipe density	7850kg/m^3
Young`s modulus	2.12×10^8 kPa
Poisson ratio	0.293
Coating thickness	-
Coating density	-
Water depth	100 m (relevant for high current situation)
Water height	1 m (single Airy wave)
Wave period	6s
Wave direction	Opposite Lay direction (180°)
Drag coefficient	1.2
Sea density	1025 kg/m^3
Sea Kinematic viscosity	1.35×10^{-6} m^2/s
Vessel property	Orcaflex default
Average Current speed	0.5 m/s (uniform)

A boundary condition is also defined for this example case. The kinematic horizontal wave particle motion is based on mean sea level (z=0) so the particle velocity above mean sea level (e.g. at the wave crest) is set to be simply equal to the velocity at the mean sea level. Orcaflex calls this option as Vertical Stretching [61].

Different direction scenarios will be taken for the current. In this project the directions will be 0°, 30°, 60°, 90°, 120°, 150°, and 180° (Figure 9.1). Cases will be named based on these directions. OrcaFlex outputs will be observed to find out which scenario gives the worst condition during pipe-lay.

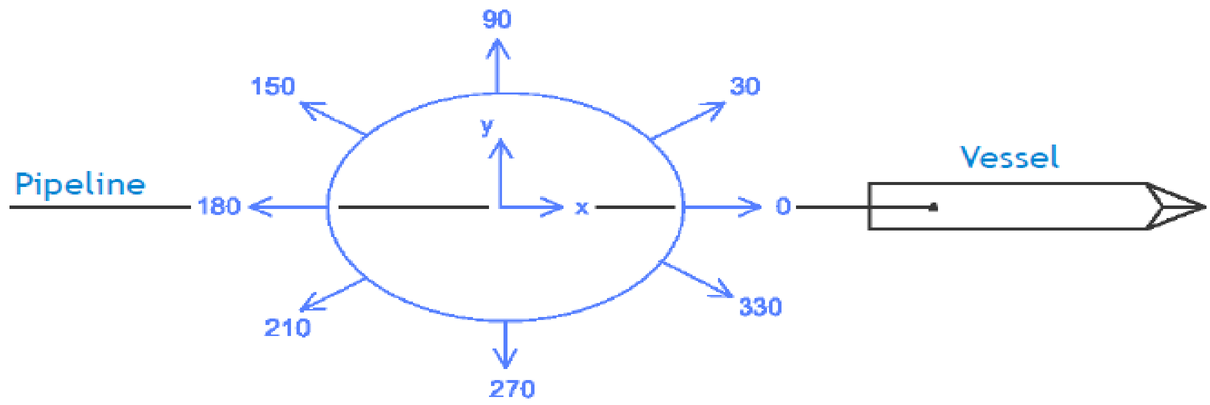

Figure 9.1 OrcaFlex global direction conventions [28]

9.2 Analysis Result

Analysis will be carried out in 2 steps. First step is a static analysis and the second is a dynamic analysis.

The static analysis will give a general overview about the system at the moment just after the current has been applied (equilibrium state) but it is not sufficient to describe how the whole system will behave due to varying loads at some period of time and that is why a dynamic analysis will also be conducted to satisfy this needs. Fortunately OrcaFlex is capable to do both analyses.

9.2.1 Static results

Brief OrcaFlex results for the static analysis can be seen in Table 9.2:

Table 9.2 Static analysis results (case1)

Cases	Tension at start of pipeline	Tension at end of pipeline	Tension at touchdown	Length of pipeline on seabed	Lateral force	Maximum roller compression	Maximum Von Mises stress
	(kN)	(kN)	(kN)	(m)	(kN)	(kN)	(MPa)
	pipe End A	pipe End B	-	start from touchdown point	tension in “Starboard Link4”	maximum tension in upperlinks	in overbend region
No current	151.61	108.34	108.32	348	0	54.38	336.48
Case 0	153.37	110.63	110.34	346	0	54.71	337.34
Case 30	154.81	111.98	111.76	346	3.4	54.95	337.87
Case 60	159.7	116.72	116.64	342	9.96	55.72	339.42
Case 90	161.97	118.9	118.88	338	12.91	56.04	339.93
Case 120	155.98	112.66	112.71	342	9.56	55.03	337.68
Case 150	150.06	106.39	106.58	348	3.28	54.07	335.63
Case 180	149.83	106.02	106.29	348	0	54.04	335.6

From Table 9.2 above it can be seen that all parameters reach most unfavorable values in Case 90° where the current flows at 90̊ direction. Tension at start of pipeline, can also be interpreted as the vessel tensioner force, goes up to 161.97 kN before it decreases as the current flows towards the vessel or opposite the lay direction i.e. 180°.

Another important parameter to be concerned is the lateral force resulting due to current. The static result shows that the capacity of the lateral support on the last roller must not be less than 12.91 kN. The highest maximum Von Mises stress occurs also in Case 90° with value of 339.93 MPa.

To have better understanding about the result, figures about effective tension and max Von Mises stress in the pipeline for Case 90° will be presented on the next page (Diagrams 9.1 and 9.2) and it can be noticed that the pipeline is under tension throughout its length.

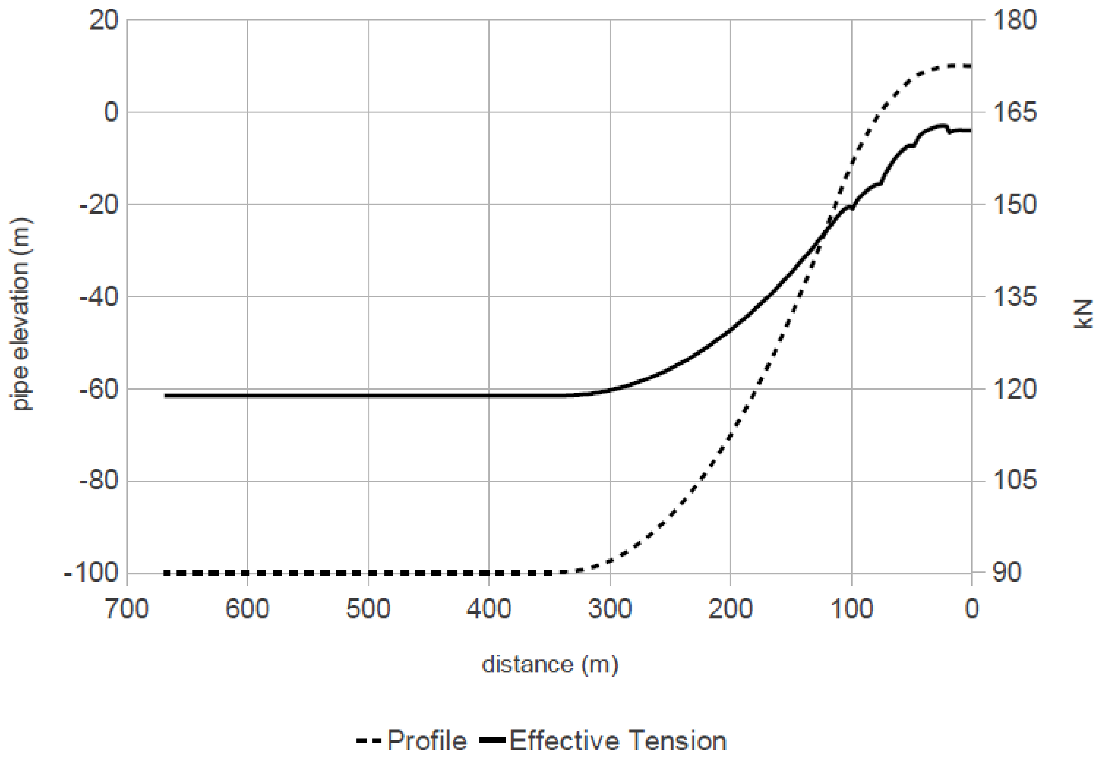

Diagram 9.1 Pipeline profile vs effective tension (Case 90).

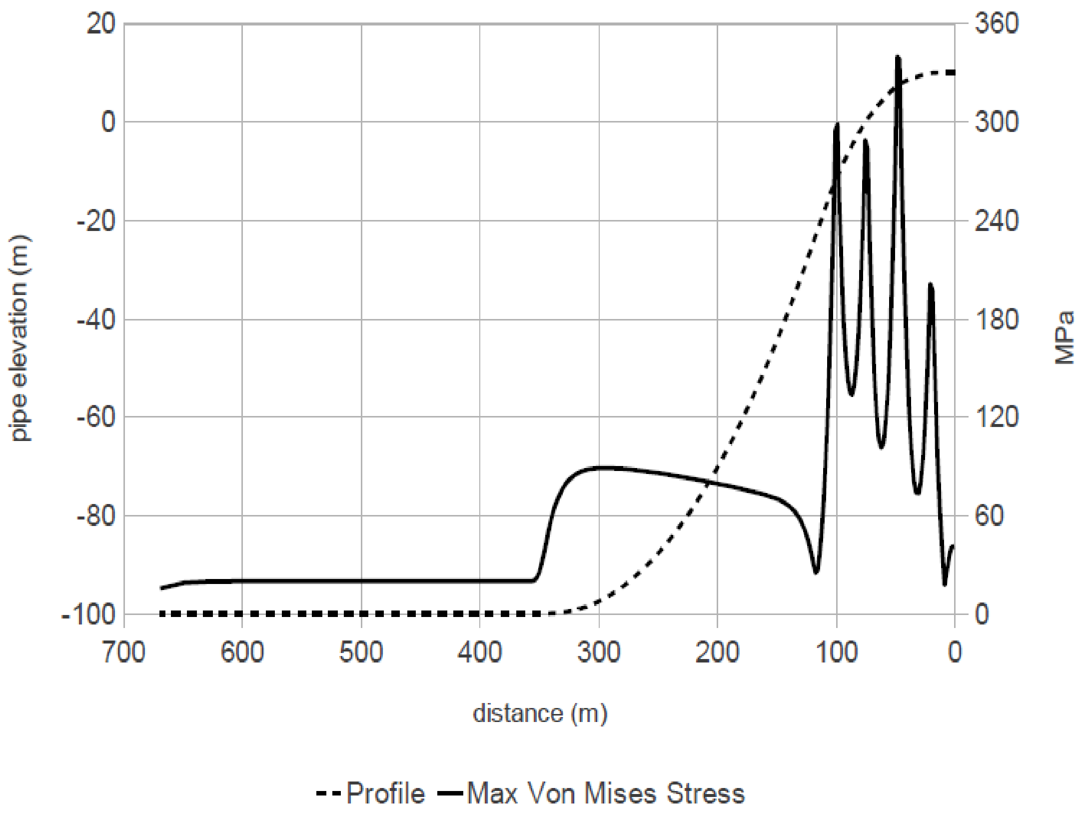

Diagram 9.2 Pipeline profile vs max Von Mises stress (Case 90).

9.2.2 Dynamic results

The dynamic analysis is a refinement of the static analysis. It will give the variation of response and stresses in the pipeline during a simulation period. 60 seconds of simulation with pre additional 6 seconds for the build-up period was done for this analysis. The results are as follow (Table 9.3):

Table 9.3 Dynamic analysis results (case1)

Cases	Max tension at start of pipeline	Max tension at end of pipeline	Max tension at touchdown	Min length of pipeline on seabed	Max lateral force	Max maximum roller compression	Max maximum Von Mises stress
	(kN)	(kN)	(kN)	(m)	(kN)	(kN)	(MPa)
	pipe End A	pipe End B	-	start from touchdown point	tension in “Starboard Link4”	maximum tension in upperlinks	in overbend region
No current	199.36	133.38	150.07	333.97	0	63.8	358.69
Case 0	210.03	143.93	165.48	332.01	0	65.08	369.2
Case 30	210.8	144.96	166.25	331.98	6.5	65.18	366.89
Case 60	215.88	150.17	171.46	327.77	16.17	66.02	363.31
Case 90	217.04	151.54	172.16	323.59	20.07	66.17	363.43
Case 120	206.43	140.87	159.51	329.74	15.2	64.88	360.74
Case 150	198.02	130.98	148.43	335.97	6.04	63.5	357.89
Case 180	196.44	129.68	146.72	336.01	0	63.27	357.4

From Table 9.3 above, despite that most of the basic parameters get their worst value in Case 90° and decrease as the current flows toward or to opposite the lay direction, it can be seen that max Von Mises is highest in Case 0° with value of 369.2 MPa and decreases as the current flows away from the lay direction.

Because of this phenomenon, comparison of tensile stress, bending stress, and hoop stress along the arc length of pipeline between Case 0° and Case 90° will be presented in Diagrams 9.3 to 9.5 on the next page since they are the fundamental for calculation of Von Mises stress.

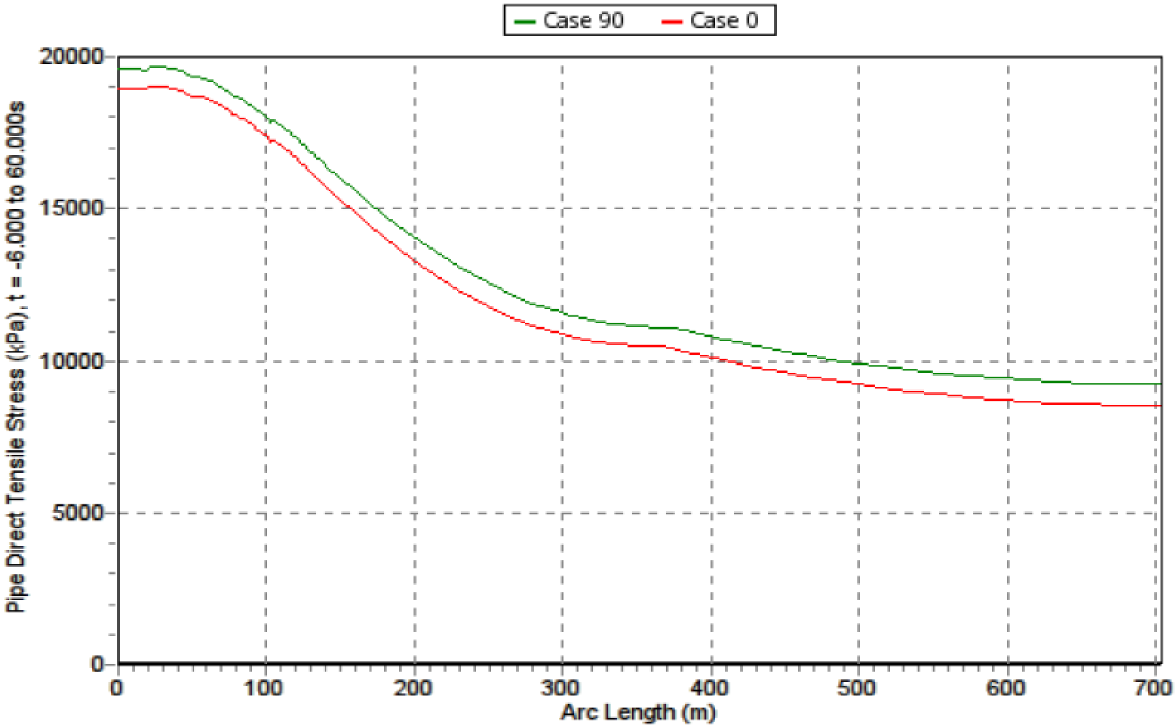

Diagram 9.3 Comparison of pipe direct tensile stress along arc length

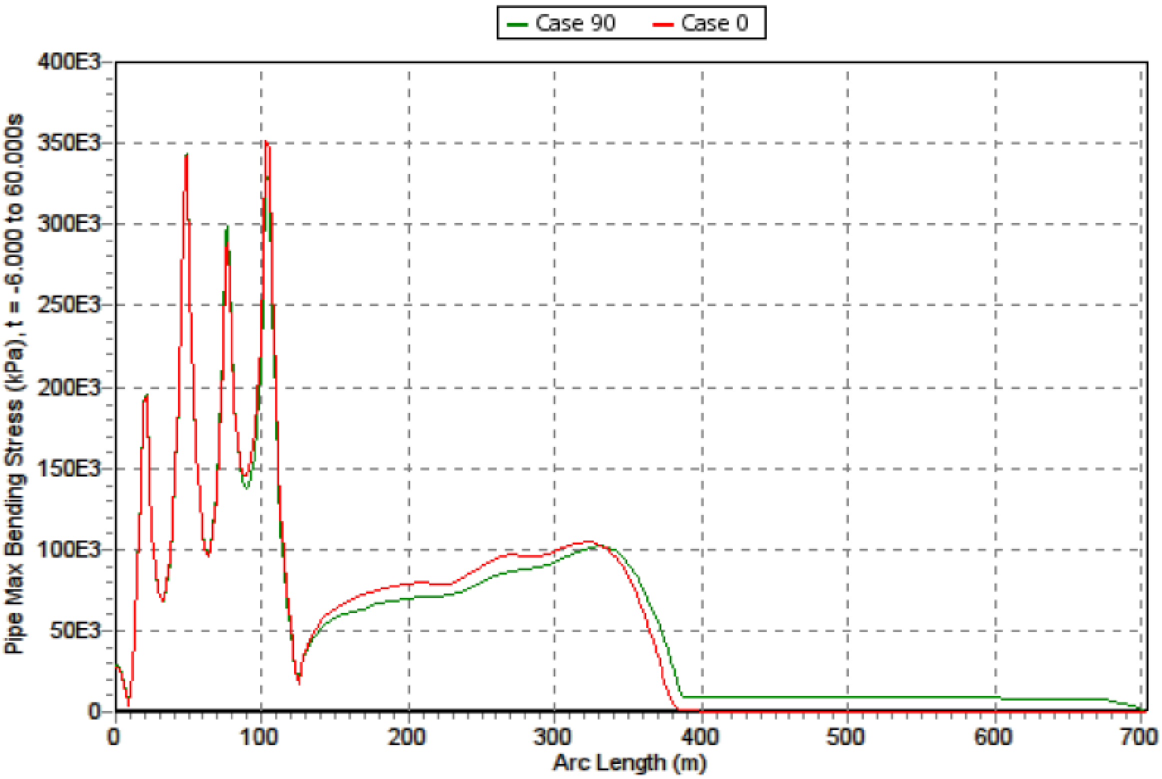

Diagram 9.4 Comparison of pipe max bending stress along arc length

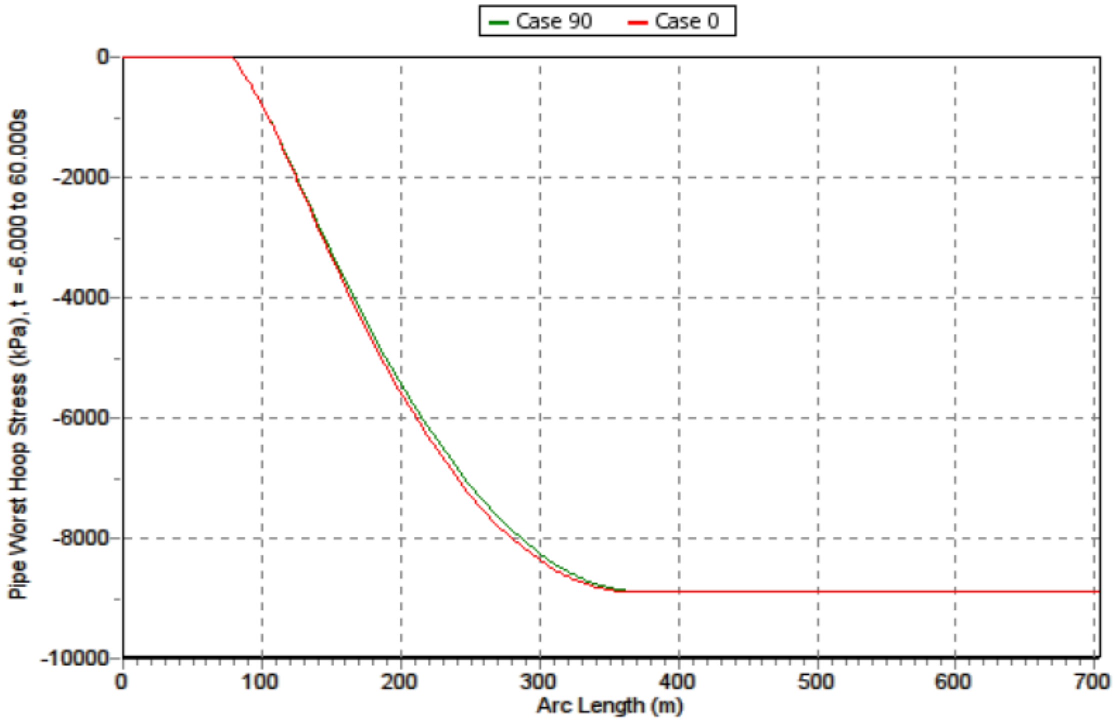

Diagram 9.5 Comparison of pipe worst hoop stress along arc length

From Diagrams 9.3 to 9.5 it can be seen that the direct tensile stress in the pipeline is higher in Case 90° compared to Case 0°. Lateral current force gives a significant effect here. On the other hand, for max bending stress, Case 0° gives a worse condition rather than Case 90°.

By deeper observations of diagram 9.4 it can be found that the highest bending stress happens at approximately 105 m arc length of the pipeline from the tensioner. This is roughly where the last roller is. The current force on the suspended length of the pipeline toward the lay direction (Case 0°) reduces the radius of curvature as the pipe comes from a supported to an unsupported region and hence the bending stress increases (Diagram 9.4).

Finally, the hoop stress is roughly similar throughout the pipeline, some differences occur near the sagbend area where Case 0° gives more hydrostatic pressure than Case 90° for the same arc length. This means that some length of the pipe in the sagbend area “reaches” Slightly deeper depth and received more pressure in Case 0°.

9.2.3 Minimum pipe grade requirement

Since the pipe grade has not been defined before, then by taking the worst Von Mises stress from the dynamic result in Case 0° and compare it to the allowable, the minimum required pipe yield strength is:

$\sigma_F = \dfrac{\sigma_e}{\eta_{ep}}$ = 369.2 [MPa] / 0.96 = 384.6 [MPa] or API 5L Grade X56

One more check needs to be done. The Von Mises stress from no environmental load condition has to be checked as well. This will be the no-current case in the static analysis since in dynamic analysis wave load is included. The minimum required yield strength is:

$$\sigma_F = \frac{\sigma_e}{\eta_{ep}} = 336.48 \text{ [MPa]} / 0.72 = 467.33 \text{ [MPa] or API 5L Grade X70}$$

So, from the two checks above the minimum pipe grade to be used can be determined now. The minimum pipe grade shall be the higher of the two check results i.e. not less than API 5L Grade X70 or equal.

9.3 Conclusion

Strong currents that occur during a pipe-lay activity give effects on the stresses in the pipeline. The pipe-lay example case gives a quick overview how the stresses in the pipeline will change as the current direction changes and also compared to when there is no current at all. The static analysis provides good understanding about how the equilibrium state of the model will be, but the dynamic analysis gives better details about the behavior of the whole system during the selected simulation period.

The tension in the upper link (bottom right), representing contact between the lay-pipe and the lower roller, remains positive throughout showing that the pipe never lifts off the roller. Contact with the starboard link and the pipe is much more chaotic, with the pipe moving from side to side throughout the simulation as a result of the out-of-plane environmental conditions [28].

Proper and comprehensive metocean data which includes current data for a particular location where the pipeline will be installed shall be provided for analysis prior the field work offshore being started. This will be even more mandatory for places that are well known of having strong current such as the Makassar Strait of Indonesia.

The analysis shows that for this particular example case the minimum pipe grade to be used is API 5L Grade X70 or equal with minimum yield strength of 467.33 MPa which is due to no-current load case in the static analysis. This is the result of the implementation of the DNV strict allowable stress criteria in an analysis without any environ-mental loads i.e. 72% of SMYS. A refinement to reduce this high pipe grade requirement can be made for example by adjusting the stinger curvature since the pipe high stresses are in the overbend region.

Chapter 10 – Case 2

Installation of flexible pipelines in sideway current

10.1 Case properties

The properties of the flexible pipe chosen for this example case with the current speed based on the Makassar Strait current data (from Section 8.2) can be seen in Table 10.1 below:

Table 10.1 Properties for pipe-lay (case 2)

Pipe dimensions	331.7 mm OD × 51.55 mm WT flexible pipe
Pipe density	3800 kg/m^3
Poisson ratio	0.5
Coating thickness	-
Coating density	-
Water depth	100 m (relevant for high current situation)
Water height	1 m (single Airy wave)
Wave period	6s
Wave direction	Opposite Lay direction (180°)
Drag coefficient	1.2
Sea density	1025 kg/m^3
Sea Kinematic viscosity	1.35×10^{-6} m^2/s
Vessel property	Orcaflex default
Average Current speed	0,5 m/s (uniform)*

Table 10.2 gives data for the flexible riser and flowline that used from 9" production riser and flowline in the Norne M project.

Table 10.2 Products' main properties (case 2)

Property	Flexible pipe
Length	730.51 m
Pipe Outer Diameter, OD	331.7 mm
Pipe Internal Diameter, ID	228.6 m
MBR, Storage	2.56 m
MBR, Installation	3.84 m
Max Axial Tension, Installation	756 kN
Max Axial Compression, Installation	15 kN
Axial Stiffness	1089 MN
Bending Stifness	157 kNm^2
Torshional Stifness	139 kNm^2/deg
Allowable Twist - Clockwise	2.25 deg/m
Allowable Twist – Anti-Clockwise	1.71 deg/m
Nominal Mass, Empty	172.3 kg/m
Nominal Mass, Flooded with Freshwater	216.7 kg/m

Different direction scenarios will be taken for the current. In this project the directions will be 0°, 30°, 60°, 90°, 120°, 150°, and 180° (Figure 9.1). Cases will be named based on these directions. OrcaFlex outputs will be observed to find out which scenario gives the "worst" condition during pipe-lay.

For the pipe density, it is possible to apply "nominal mass, flooded with freshwater" in table 10.2 into the pipe weight section in OrcaFlex software. And also we can use axial, bending and torsional stiffness from table 10.2 instead of Young`s modulus to define the stiffness of the product.

After reaching the analysis results, the results will be compared with the product limitations, i.e. MBR (Minimum Bending Ratio), Max Tension and if no results are exceeding the limitations, and then it is good to go for installation!

10.2 Analysis Result

The analysis will be carried out in 2 steps. The first step is a static analysis and the second is a dynamic analysis.

The static analysis will give a general overview of the status of the system at the moment just after the current has been applied (equilibrium state) but it is not sufficient to describe how the whole system will behave due to varying loads at some period of time and that is why a dynamic analysis will also be conducted to satisfy this needs. Fortunately, OrcaFlex is capable to do both analyses. Appendix B

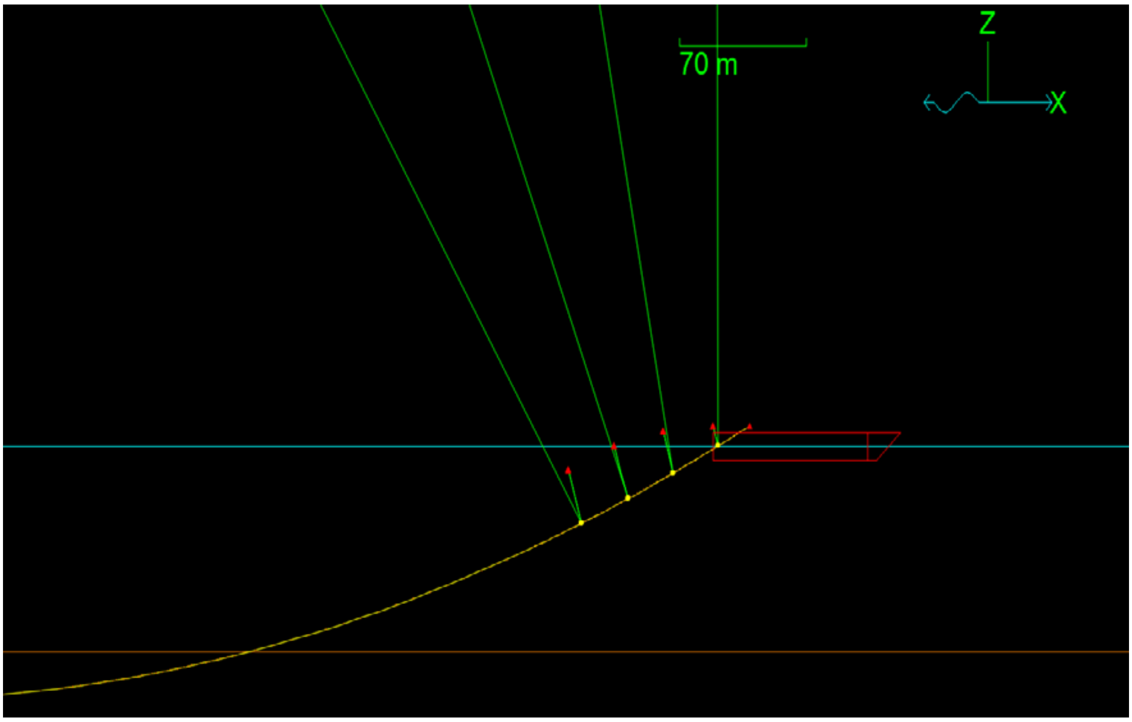

Figure 10.1 Flexible pipe analysis as modeled in Orcaflex (reset state)

The Reset button returns OrcaFlex to the reset state, in which we can edit the data freely. (While a simulation is active you can only edit certain non-critical items, such as the colors used for drawing.) In the Reset state (Figure 10.1) we can freely change the model and edit the data. No results are available [28].

OrcaFlex is calculating the static position of the model (Figure10.2). After the static calculation is complete, the static position results are available. We are allowed to make changes to the model when in this state but if we make any changes (except for very minor changes like colors used) then the model will be automatically reset and the statics results will be lost. When the dynamic simulation (Figure 10.3) is running the results of the simulation are available we can examine the model data, but only make minor changes (e.g. colors used) [28].

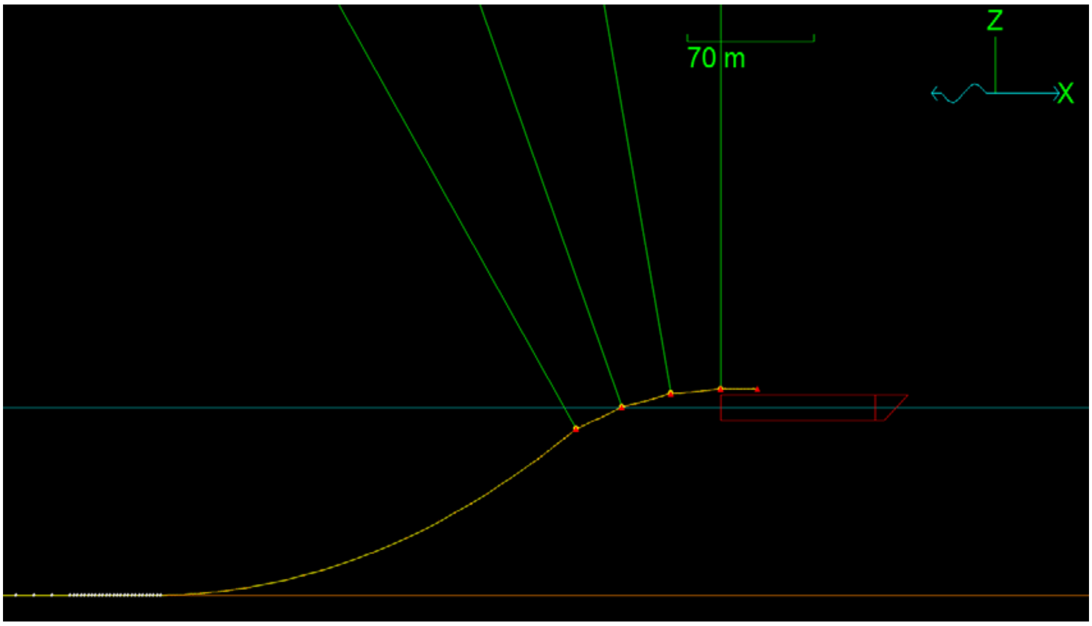

Figure 10.2 Flexible pipe analyses as modeled in Orcaflex (Single statics simulation)

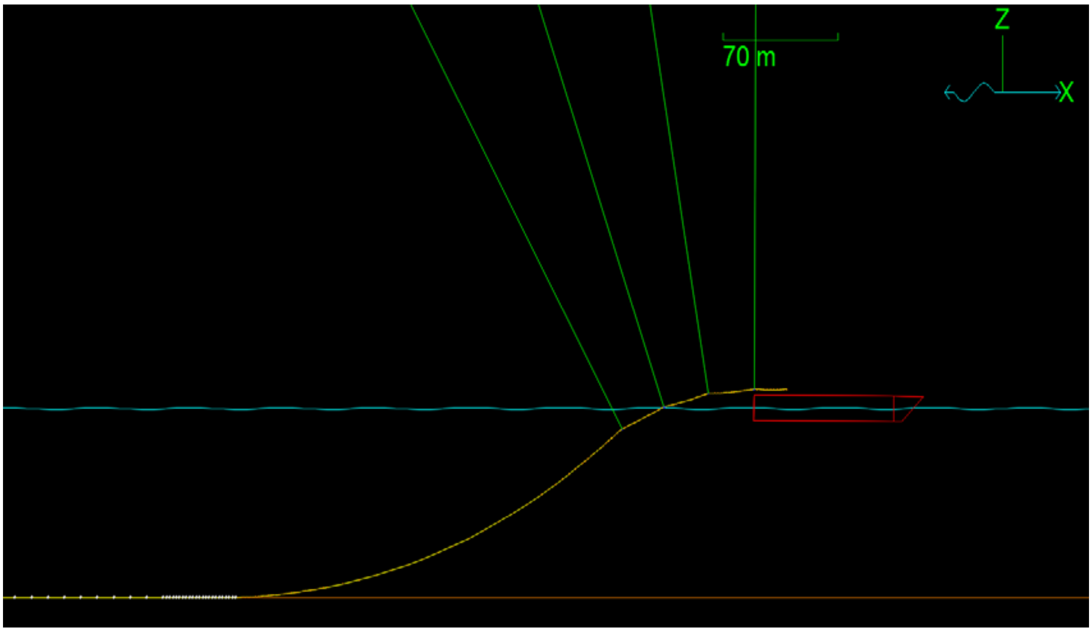

Figure 10.3 Flexible pipe analyses as modeled in Orcaflex (Dynamic simulation)

10.2.1 Static results

Orcaflex static analysis has been done in part 10.2.1, but since, as observed in the analysis of installation of the steel pipe, the 90° direction current is the worst case, therefore in this part we have just put diagrams for the 90° direction current although all mentioned current directions for steel pipe have been evaluated. Of course for much more accurate investigations all diagrams related to 0°, 30°, 60°, 120°, 150° and 180°directions currents and also no current case are available in Appendix C. As it is shown here, in this part we are going to perform some investigations and interpretations about "Wall Tension vs Arc Length" and "Max von Misses Stress vs Arc Length" and "Pipe bending Radius vs Arc Length" diagrams. Brief OrcaFlex results for the static analysis can be seen in diagrams below:

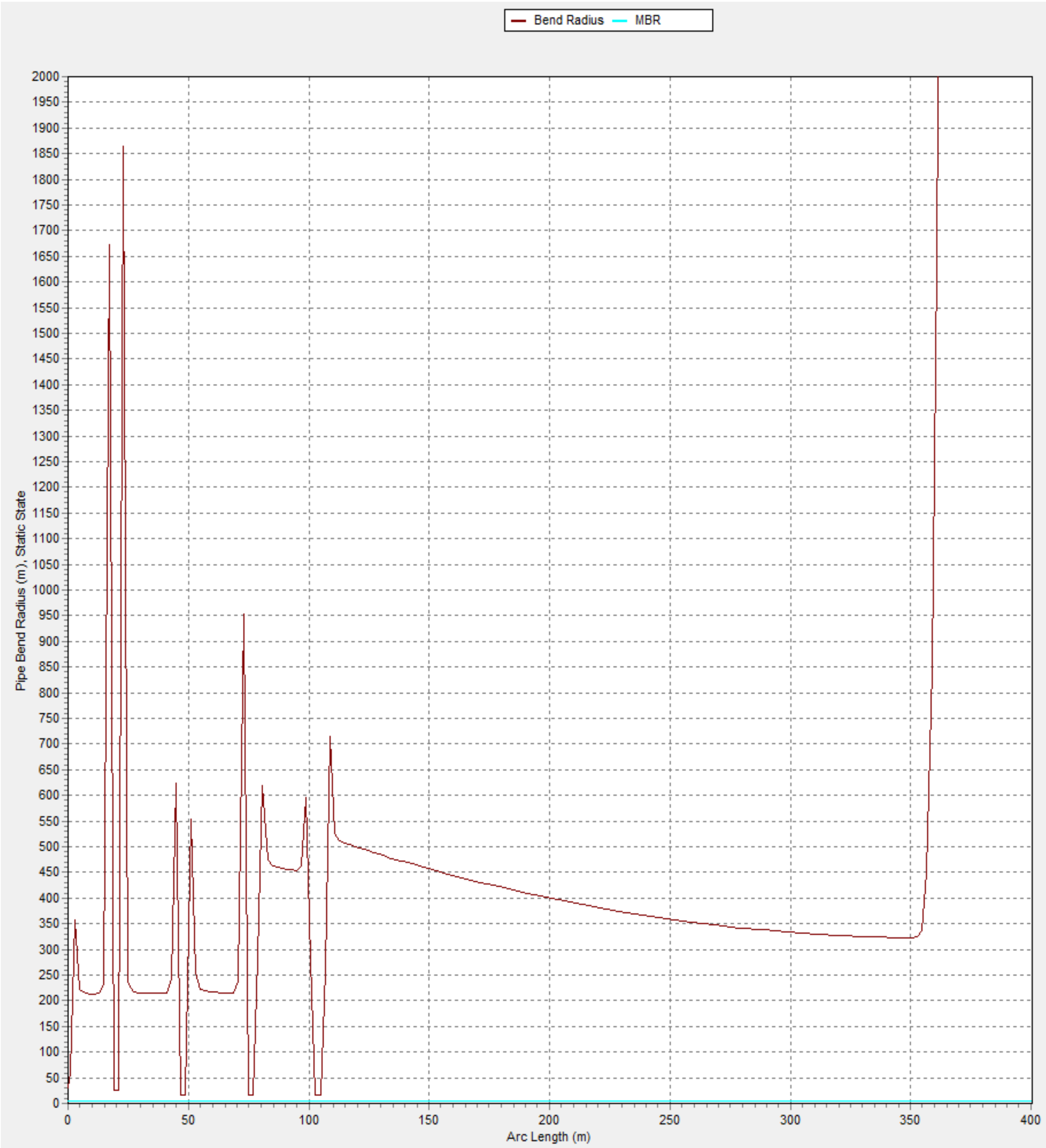

Diagram 10.1 Pipe bending Radius vs Arc Length, Static State (Case 90°)

Diagram 10.1 is describing Pipe bending Radius (m) vs Arc Length (m) in Static State. As we can see until arc length of 100m (the overbend region) there is a kind of vague relation between X axis and Y axis, lots of up and downs are visible in the mentioned length of pipe, and the minimum pipe bend radius happens at an arc length of about 48.92 m, equal to 15.42 m (accurate numbers for other cases are available on EXCEL data disc). The reason for the variation is the extra bending when the pipe passes the rollers on the stinger. After a length of 100 m, a kind of mild decrease appears until a length of about 350 m and exactly after that a sudden sharp increase is occurring in the pipe bend radius.

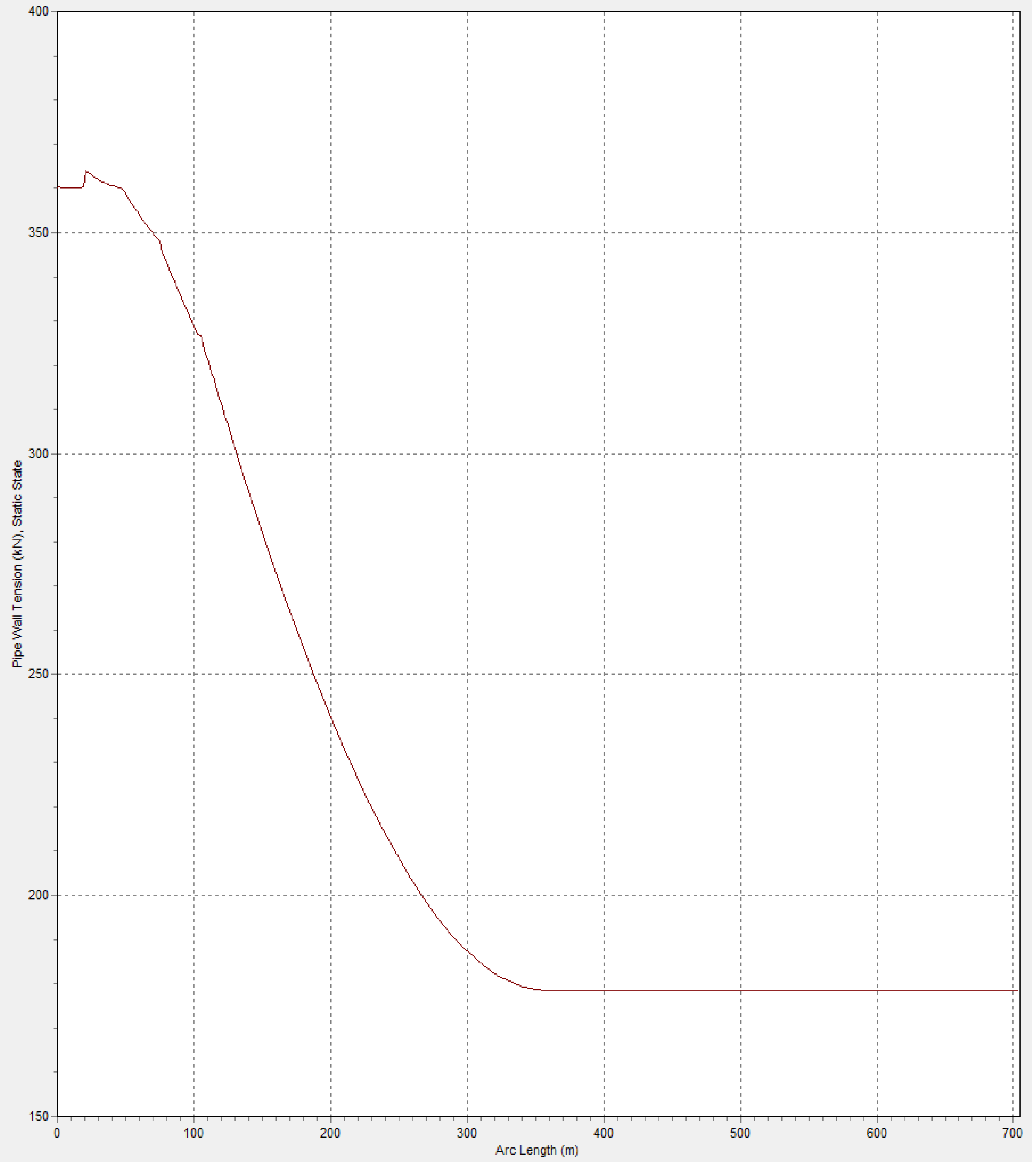

Diagram 10.2 Wall Tension vs Arc Length, Static State (Case 90°)

Diagram 10.2 is describing Tension (kN) vs Arc Length (m) related to Static State. Until a length of 300 m we have a relatively mild decrease in the amount of wall tension. After that a kind of stable tension occurs with differences almost non-visible on sea bed. Maximum tension peack happens at an arc length of about 21 m, equal to 363.83 kN in tensioner region. (Accurate numbers for other cases are available on the EXCEL data disc).

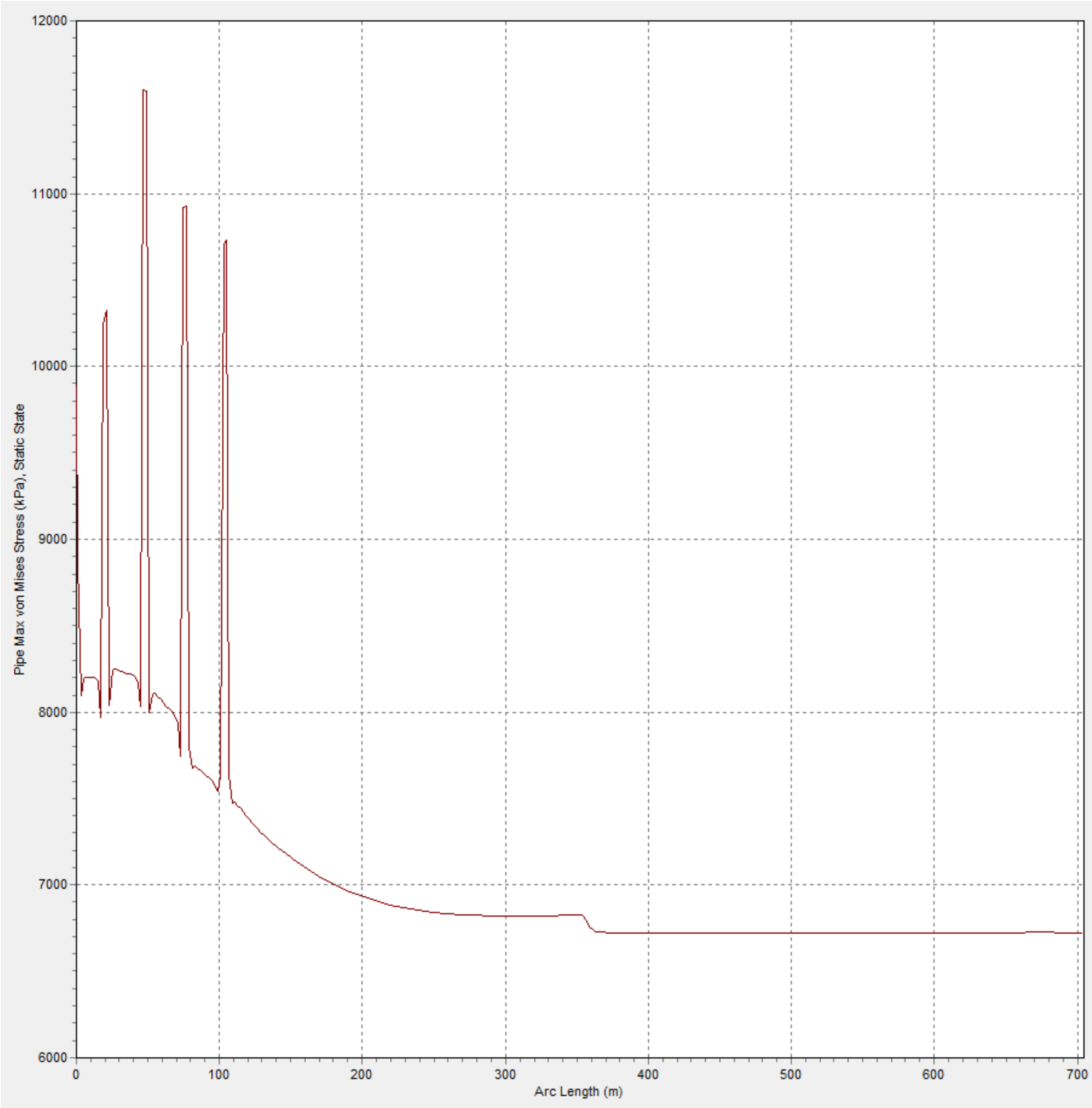

Diagram 10.3 Max von Mises Stress Tension vs Arc Length, Static State (Case 90°)

Diagram 10.3 is describing Max von Mises Stress (kPa) vs arc length (m). It is interesting that there is significant instability in the amount of maximum von Mises stress with lots of up and downs and peacks in the overbend region. The maximum von Mises stress for case 90° relates to the arc length of around 46 m which is 11602 kPa. After that we have a decrease in a kind of curvy way until an arc length of 350 m with stress equal to 6800 kPa. After this step we have a von Mises stress which is around 6700 kPa on the seabed.

10.2.2 Dynamic results

The dynamic analysis is a refinement of the static analysis. It gives the variation of the response and stresses in the pipeline during a simulation period. 60 seconds of simulation with an additional 6 seconds for the build-up period was done for this analysis.

In this part we have just put the diagrams for 90° directions currents although all mentioned current directions for steel pipe have been evaluated. Of course for much more accurate investigations all diagrams related to 0°, 30°, 60°, 120°, 150° and 180° directions current and also the no current case are available in Appendix D. Brief OrcaFlex results for the dynamic analysis can be seen in the diagrams below:

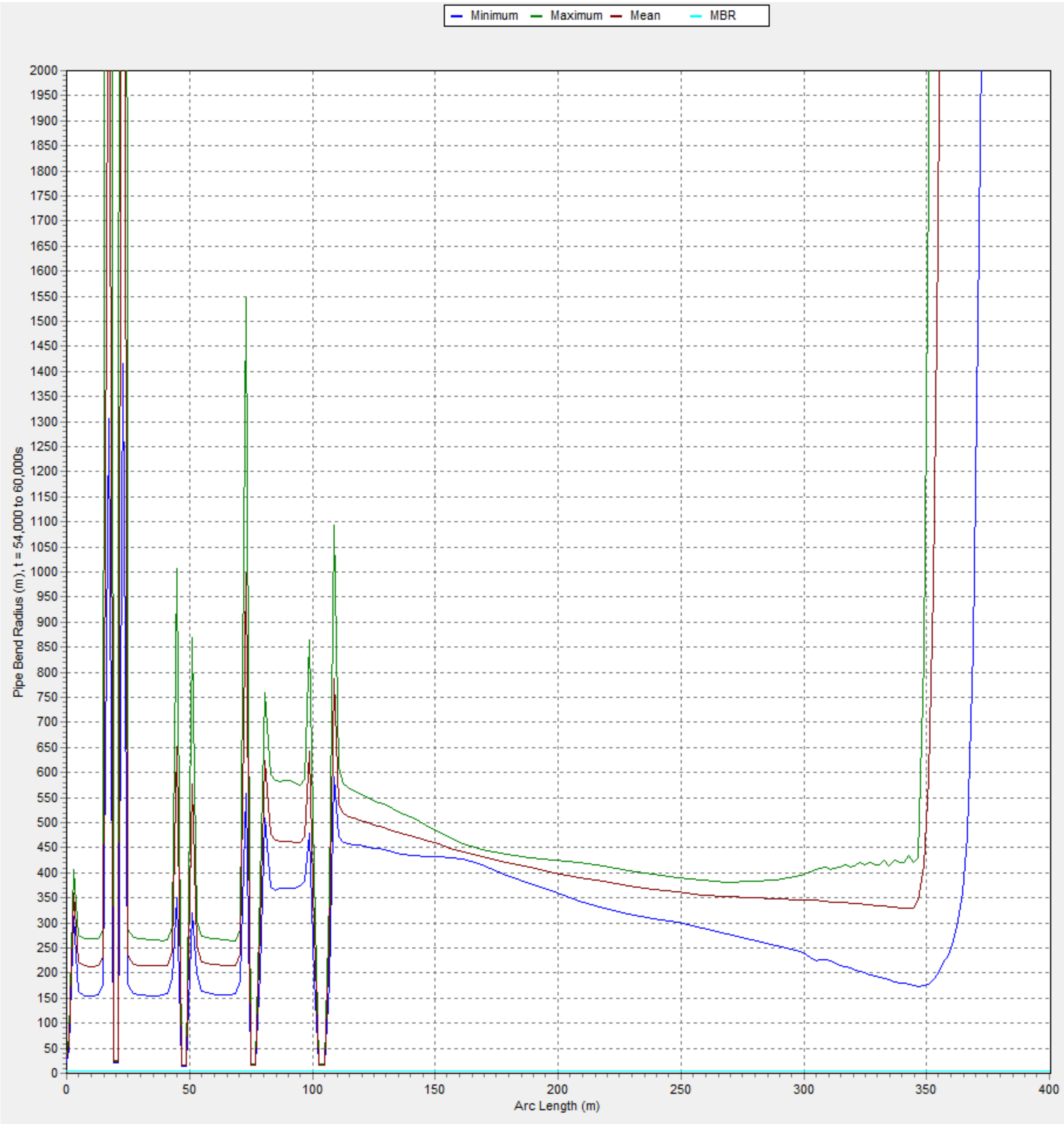

Diagram 10.4 Pipe bending Radius vs Arc Length, Dynamic State (Case 90°)

Diagram 10.4 is describing the Pipe bend Radius (m) vs Arc Length (m) in the Dynamic State. As we can see until an arc length of 100 m (in the overbend region) there is a kind of vague relation between the X axis and the Y axis, lots of up and downs are visible for the mentioned length of the pipe. Minimum pipe bend radius happens at an arc length of about 48.92 m; equal to 16.34 m (accurate numbers for other cases are available on the EXCEL data disc). After a length of 100 m, a kind of mild decrease appears until a length of about 350 m and exactly after that a sudden sharp increase is occurring in the pipe bend radius. The minimum bending radius (MBR) is equal to13.58 m, as it is clear in the diagram, all bending radius are, more than the MBR so the check point is fulfilled.

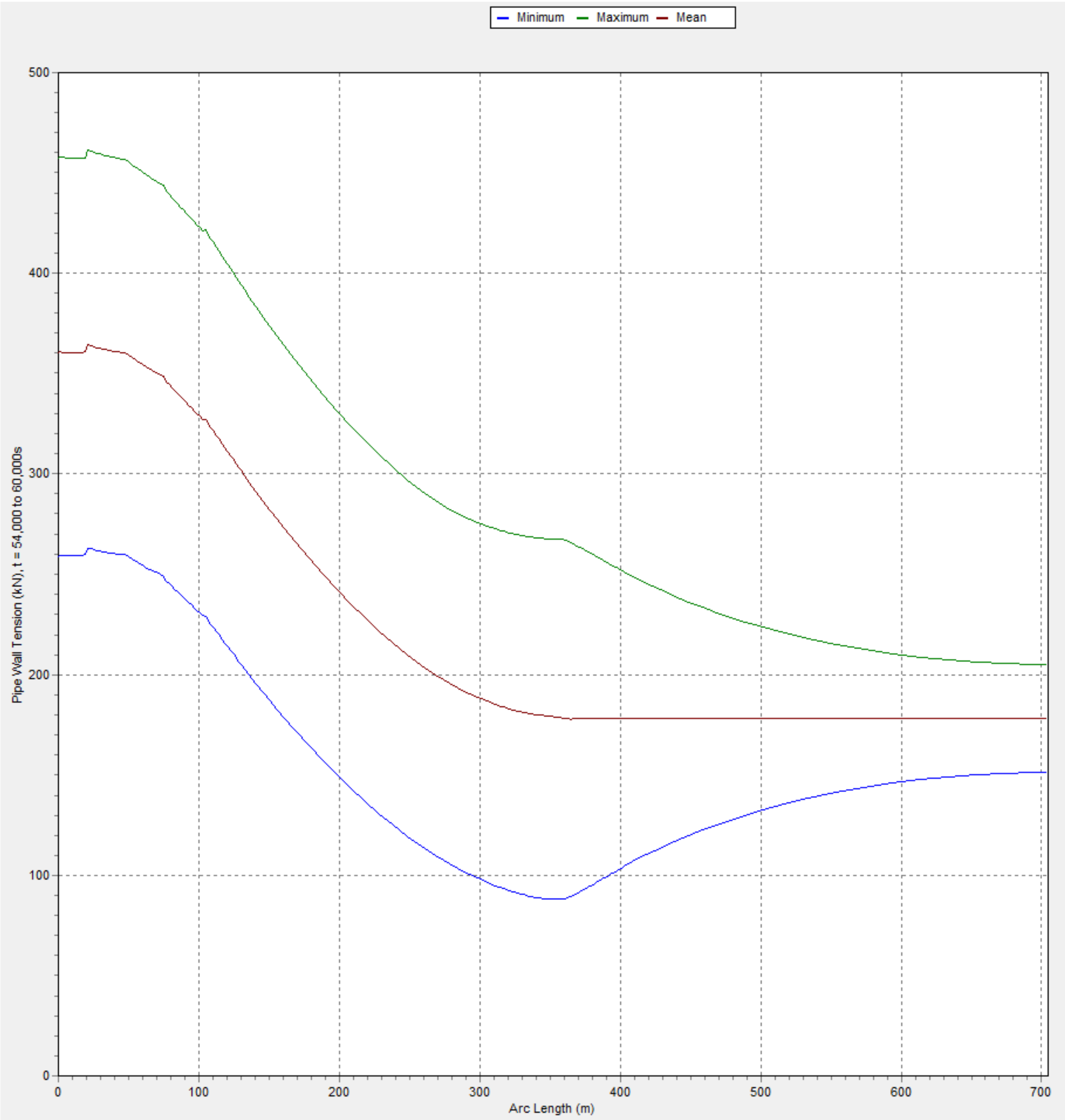

Diagram 10.5 Wall Tension vs Arc Length, Dynamic State (Case 90°)

Diagram 10.5 is describing the Tension (kN) vs the Arc Length (m) related to the Dynamic State. Until an arc length of 300 m we have relatively mild decrease in the amount of the wall tension. After that, a kind of stable tension occurs for the pipe on the sea bed. The maximum tension peak happens at an arc length of about 21 m, equal to 461.23 kN in the tension region. (Accurate numbers for other cases are available on the EXCEL data disc).

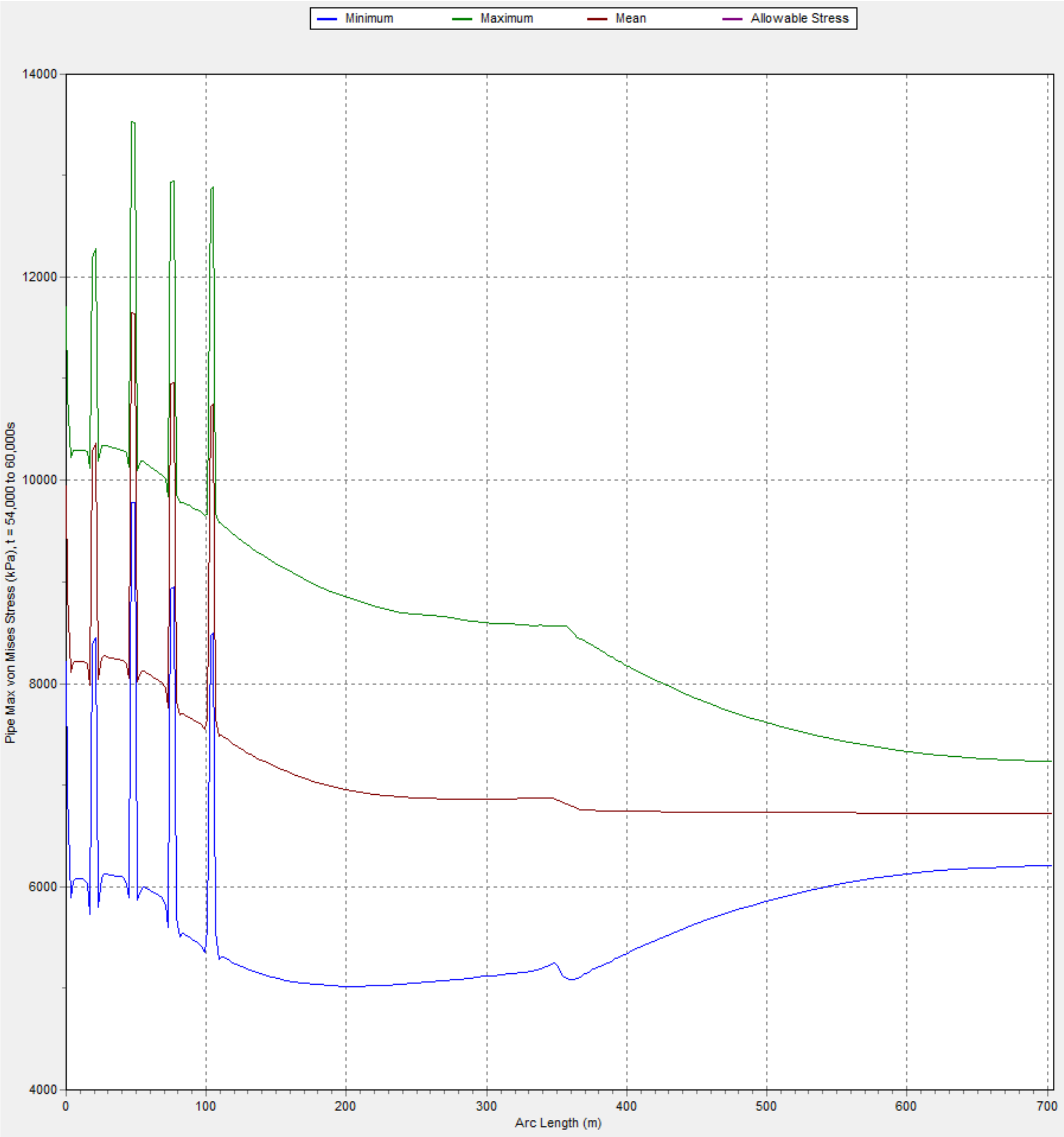

Diagram 10.6 Max von Mises Stress vs Arc Length, Dynamic State, (Case 90°)

Diagram 10.6 is describing Max von the Mises Stress (kPa) vs arc length (m). It is interesting that there is significant instability in the amount of maximum von Mises stress with lots of up and downs and peak in the overbend region. The maximum von Mises stress for case 90° relates to an arc length of around 46 m which is 13527.51 kPa. After that we have decrease in a kind of a curvy way until an arc length of 350 m with stress equal to 6800 kPa. After this step we have stable von Mises stress which is around 6700 kPa on the seabed.

10.3 Conclusion

Table 10.3 Dynamic analysis results (case2)

Cases	Max effective Tension	Min bend radius	Max wall tension	Max von Mises stress
Unit	kN	m	kN	kPa
No Current	452,523568 (at 20,99 m)	16,2820684 (at 48,92 m)	452,523568 (at 20,99 m)	13348,018 (at 46,92 m)
Case 0°	456,058447 (at 20,99 m)	16,2832496 (at 48,92 m)	456,058447 (at 20,99 m)	13425,9168 (at 46,92 m)
Case 30°	456,050268 (at 20,99 m)	16,2889628 (at 48,92 m)	456,050268 (at 20,99 m)	13424,6066 (at 46,92 m)
Case 60°	459,586148 (at 20,99 m)	16,3204795 (at 48,92 m)	459,586148 (at 20,99 m)	13495,4788 (at 46,92 m)
Case 90°	461,230999 (at 20,99 m)	16,3411574 (at 48,92 m)	461,230999 (at 20,99 m)	13527,5152 (at 46,92 m)
Case 120°	455,126438 (at 20,99 m)	16,2915665 (at 48,92 m)	455,126438 (at 20,99 m)	13403,466 (at 46,92 m)
Case 150°	449,469906 (at 20,99 m)	16,239645 (at 48,92 m)	449,469906 (at 20,99 m)	13289,7434 (at 46,92 m)
Case 180°	448,173564 (at 20,99 m)	16,2300414 (at 48,92 m)	448,173564 (at 20,99 m)	13262,649 (at 46,92 m)

From Table 10.3 above, despite that most of the basic parameters get their worst value in case 90° and decrease as the current flows toward the lay direction, it can be seen that max Von Mises is highest in case 90° with value of 13527.5 kPa at an arc length 46.9 m and decreases as the current flows away from the lay direction. As we see, the maximum tension occurs at an arc length of 21 m with maximum value of 461.23 kN in all cases. Also the minimum bending radius is equal to 16.2 m for all cases and is more than the defined MBR.

Through the above analysis, we have documented the feasibility of the laying operation. Similar analysis must be carried out for any laying operation of flexible pipes.

It should be noted that the reason for the variation of parameters in the overbend is the extra bending when the pipe passes the rollers on the stinger. The stinger geometry could be adjusted to minimize these variations.

Chapter 11 – Conclusions and Recommendations

11.1 Conclusion

The objective of this master thesis is to identify different pipeline solutions and analyse the installation by the S-lay pipeline installation method for a steel pipeline as case 1 and a flexible pipeline as case 2 by using OrcaFlex software.

The comparison between the tension(the vertical force acting on the pipe) and the von Mises stresses in the steel pipe and flexible pipe chosen for this example case with the current speed based on the Makassar Strait very strong current data (from Section 8.2) can be seen in tables 11.1 and 11.2 below:

Table 11.1 Comparison of tension in steel pipe and flexible pipe, Dynamic state

Cases	Steel pipeline kN	Flexible pipeline kN
No Current	199,36 (at 22,99 m)	452,52 (at 20,99 m)
Case 0°	210,03 (at 22,99 m)	456,05 (at 20,99 m)
Case 30°	210,8 (at 22,99 m)	456,05 (at 20,99 m)
Case 60°	215,88 (at 22,99 m)	459,58 (at 20,99 m)
Case 90°	217,04 (at 22,99 m)	461,23 (at 20,99 m)
Case 120°	206,43 (at 22,99 m)	455,12 (at 20,99 m)
Case 150°	198,02 (at 22,99 m)	449,46 (at 20,99 m)
Case 180°	196,44 (at 22,99 m)	448,17 (at 20,99 m)

Table 11.2 Comparison of von Mises stresses in steel pipe and flexible pipe, Dynamic state

Cases	Steel pipeline MPa	Flexible pipeline kPa
No Current	358,69 (at 48,92 m)	13348,018 (at 46,92 m)
Case 0°	369,2 (at 48,92 m)	13425,9168 (at 46,92 m)
Case 30°	366,89 (at 48,92 m)	13424,6066 (at 46,92 m)
Case 60°	363,31 (at 48,92 m)	13495,4788 (at 46,92 m)
Case 90°	363,43 (at 48,92 m)	13527,5152 (at 46,92 m)

Case 120°	360,74 (at 48,92 m)	13403,466 (at 46,92 m)
Case 150°	357,89 (at 48,92 m)	13289,7434 (at 46,92 m)
Case 180°	357,4 (at 48,92 m)	13262,649 (at 46,92 m)

From tables 11.1 and 11.2 above it can be seen that all parameters reach the most unfavorable values in Case 90° where the current flows at 90° direction both for the analysis of the steel pipe and the flexible pipe. The highest maximum Von Mises stress occurs also in Case 90°.

As we see in table 11.1 the tension in the flexible pipeline is more than the tension in the steel pipeline but vice versa for the von Mises stresses which is more in the steel pipeline than the von Mises stresses in flexible pipeline!

Some conclusions that can be drawn from the thesis work are:

- From the analysis results in chapters 9 and 10, it can be concluded that with reducing tension the pipeline system can be installed on that area. Therefore laying operation is practical if just pay attention to the tension of the pipe.
- Strong currents that occur during a pipe-lay activity give effects on the stresses in the pipeline. Most of the basic parameters get their worst value in the Case 90° and decrease as the current flows toward or to opposite the lay direction. As observed in the analysis results by paying attention to the von Mises stress, bending radius and tension the “worst” case occurs when the current is coming from the back. It means the 90° direction current.
- It should be noted that the reason for the variation of parameters in the overbend region is the extra bending when the flexible pipe passes the rollers on the stinger. The stinger geometry should be adjusted to minimize these variations.
- In the overbend region applying the steel pipe has a better bending radius results in comparison with the flexible pipe because of the lower bending of steel pipe when passes the rollers on the stinger.
- The tension in the upper link, representing the contact force between the lay-pipe and the lower roller, remains positive throughout showing that pipe never lift off the roller.
- With the actual axial tension used for the simulations (see table 10.2), pipelying should be safe from overstresses in the sagbend region.

11.2 Recommendations for further works

Based on the findings from the thesis work, some recommendations are given for further work:

- In this thesis, only one wave type (single Airy wave) was considered in the analysis. All wave types should be consider in the analysis to give more accurate results.
- S-lay pipeline installation case has been taken for analysis in this thesis. Further studies can be carried out with different installation methods such as J-lay.
- For S-lay the rollers on the stinger should be adjusted to minimize stresses in the overbend region, this should be reflected in a new analysis
- In order to reach more accurate results, other environmental conditions can be identified and added or changed such as wind, current speed, wave height, etc.

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Appendix A

Von Mises comparison

Comparison of Von Mises stress calculations between Orcaflex and DNV method as described in Section 5 is presented below. Static analysis of Case 90 from pipelay example case is taken for the comparison. All formulas refer to Section 5. Forces and moments resulted from Orcaflex output are taken for DNV stress calculations.

$$ID = OD - 2t \qquad W = \frac{I}{0.5\,OD}$$

$$A_z = \frac{\pi}{4}\left(OD^2 - ID^2\right) \qquad I = \frac{\pi}{64}\left(OD^4 - ID^4\right)$$

OD = 250 mm　　T = 15 mm　　ID = 220 mm

A_z = 0,011 m　　I = 7.68 e-5 m　　W = 6.14e-4 m

Table A.1 Von Mises Stress Comparison

Orcaflex Output					DNV Calculation				
Segment	Z (m)	Bend Moment (kNm)	Wall Tension (kN)	Max Von Mises Stress (kPa)	Axial Stress (MPa)	Bending Stress (MPa)	Hoop Stress (MPa)	Von Mises Stress (MPa)	Deviation (%)
1	10.001	16.337	161.965	41.231	14.626	26.605	0.000	41.231	0.000
2	10.005	16.079	161.969	40.811	14.626	26.185	0.000	40.811	0.000
3	10.013	13.052	161.979	35.884	14.627	21.256	0.000	35.883	0.005
4	10.024	7.136	161.992	26.256	14.628	11.622	0.000	26.250	0.024
5	10.037	1.921	162.005	17.776	14.629	3.128	0.000	17.757	0.111
6	10.050	14.441	162.010	38.163	14.630	23.517	0.000	38.146	0.043
7	10.058	30.955	161.996	65.055	14.628	50.410	0.000	65.038	0.025
8	10.060	52.112	161.944	99.505	14.624	84.865	0.000	99.488	0.017
9	10.048	78.754	161.830	142.883	14.613	128.251	0.000	142.864	0.013
10	10.017	111.938	161.613	196.907	14.594	182.292	0.000	196.886	0.011
11	9.959	114.544	162.666	201.239	14.689	186.535	0.000	201.224	0.008
12	9.873	86.666	162.762	155.844	14.697	141.135	0.000	155.833	0.007
13	9.765	65.624	162.766	121.575	14.698	106.869	0.000	121.567	0.007
14	9.642	50.581	162.714	97.069	14.693	82.371	0.000	97.064	0.005
15	9.506	40.934	162.624	81.349	14.685	66.662	0.000	81.347	0.002
16	9.361	36.300	162.511	73.789	14.675	59.114	0.000	73.789	0.000
17	9.206	36.490	162.379	74.087	14.663	59.424	0.000	74.086	0.000
18	9.043	41.510	162.228	82.250	14.649	67.599	0.000	82.248	0.003
19	8.869	51.556	162.052	98.598	14.633	83.960	0.000	98.593	0.005
20	8.683	67.024	161.838	123.771	14.614	109.149	0.000	123.763	0.007

21	8.480	88.519	161.565	158.755	14.589	144.154	0.000	158.743	0.007
22	8.256	116.883	161.198	204.916	14.556	190.344	0.000	204.901	0.008
23	8.004	153.220	160.686	264.049	14.510	249.519	0.000	264.030	0.007
24	7.715	198.934	159.952	338.433	14.444	323.965	0.000	338.409	0.007
25	7.377	199.883	159.399	339.927	14.394	325.511	0.000	339.905	0.006
26	6.992	156.072	159.543	268.588	14.407	254.164	0.000	268.571	0.006
27	6.569	121.669	159.471	212.553	14.400	198.139	0.000	212.540	0.006
28	6.117	95.320	159.258	169.619	14.381	155.229	0.000	169.610	0.005
29	5.642	75.982	158.954	138.096	14.354	123.737	0.000	138.090	0.004
30	5.149	62.888	158.588	116.737	14.321	102.414	0.000	116.734	0.002
31	4.642	55.517	158.182	104.695	14.284	90.410	0.000	104.694	0.001
32	4.121	53.572	157.744	101.486	14.244	87.242	0.000	101.486	0.000
33	3.588	56.964	157.278	106.970	14.202	92.766	0.000	106.969	0.001
34	3.041	65.812	156.780	121.336	14.157	107.175	0.000	121.333	0.003
35	2.479	80.440	156.236	145.112	14.108	130.997	0.000	145.106	0.005
36	1.898	101.390	155.626	179.177	14.053	165.114	0.000	179.167	0.006
37	1.294	129.435	154.915	224.788	13.989	210.785	0.000	224.774	0.006
38	0.659	165.604	154.051	283.615	13.911	269.687	0.000	283.597	0.006
39	-0.014	169.054	153.262	289.158	13.840	275.306	-0.001	289.146	0.004
40	-0.726	139.045	152.904	240.284	13.807	226.435	-0.061	240.273	0.005
41	-1.469	115.679	152.451	202.222	13.766	188.384	-0.123	202.212	0.005
42	-2.239	98.009	151.910	173.430	13.718	159.609	-0.188	173.420	0.006
43	-3.030	85.392	151.305	152.862	13.663	139.062	-0.254	152.852	0.007
44	-3.841	77.381	150.654	139.792	13.604	126.016	-0.322	139.781	0.008
45	-4.669	73.699	149.965	133.770	13.542	120.020	-0.391	133.758	0.009
46	-5.512	74.212	149.244	134.578	13.477	120.855	-0.462	134.564	0.011
47	-6.372	78.912	148.489	142.202	13.409	128.508	-0.534	142.185	0.013
48	-7.249	87.920	147.696	156.842	13.337	143.179	-0.607	156.820	0.014
49	-8.144	101.513	146.855	178.943	13.261	165.314	-0.682	178.918	0.014
50	-9.060	120.139	145.949	209.237	13.179	195.647	-0.759	209.207	0.015
51	-10.000	144.440	144.951	248.766	13.089	235.221	-0.838	248.731	0.014
52	-10.970	175.267	143.825	298.913	12.988	285.424	-0.919	298.872	0.014
53	-11.976	172.901	143.644	295.092	12.971	281.570	-1.003	295.045	0.016
54	-13.017	137.265	143.092	237.053	12.921	223.537	-1.091	237.005	0.020
55	-14.085	107.879	142.400	189.181	12.859	175.682	-1.180	189.133	0.025
56	-15.174	83.652	141.613	149.704	12.788	136.228	-1.271	149.655	0.033
57	-16.278	63.687	140.761	117.163	12.711	103.715	-1.364	117.113	0.043
58	-17.394	47.254	139.864	90.372	12.630	76.953	-1.458	90.321	0.056
59	-18.519	33.772	138.939	68.385	12.546	54.998	-1.552	68.333	0.076
60	-19.649	22.815	137.994	50.510	12.461	37.154	-1.646	50.458	0.103
61	-20.783	14.196	137.036	36.446	12.374	23.118	-1.742	36.395	0.141
62	-21.919	8.406	136.072	26.990	12.287	13.689	-1.837	26.941	0.181
63	-23.056	7.348	135.103	25.236	12.200	11.967	-1.932	25.188	0.189
64	-24.191	10.183	134.134	29.810	12.112	16.582	-2.027	29.760	0.168
65	-25.325	13.752	133.165	35.582	12.025	22.395	-2.122	35.529	0.150
66	-26.456	17.062	132.197	40.934	11.938	27.786	-2.217	40.877	0.139
67	-27.583	19.950	131.233	45.599	11.850	32.489	-2.311	45.539	0.131
68	-29.543	23.737	129.556	51.701	11.699	38.656	-2.476	51.637	0.125
69	-32.322	27.851	127.180	58.312	11.484	45.356	-2.708	58.242	0.122
70	-35.064	30.627	124.837	62.746	11.273	49.876	-2.938	62.670	0.122
71	-37.768	32.556	122.529	65.803	11.064	53.017	-3.165	65.721	0.125

72	-40.429	33.956	120.257	68.000	10.859	55.297	-3.388	67.913	0.128
73	-43.046	35.027	118.023	69.665	10.658	57.042	-3.607	69.574	0.132
74	-46.869	36.188	114.756	71.438	10.363	58.932	-3.927	71.340	0.138
75	-51.822	37.441	110.531	73.329	9.981	60.973	-4.342	73.222	0.146
76	-56.574	38.522	106.476	74.945	9.615	62.733	-4.741	74.831	0.152
77	-61.119	39.526	102.599	76.444	9.265	64.368	-5.121	76.323	0.158
78	-65.448	40.489	98.906	77.883	8.931	65.937	-5.484	77.756	0.163
79	-69.552	41.423	95.405	79.281	8.615	67.458	-5.828	79.149	0.168
80	-73.425	42.329	92.101	80.641	8.317	68.933	-6.153	80.503	0.172
81	-77.058	43.204	89.001	81.957	8.037	70.357	-6.457	81.814	0.175
82	-80.444	44.041	86.112	83.221	7.776	71.722	-6.741	83.073	0.178
83	-83.576	44.837	83.439	84.423	7.535	73.017	-7.003	84.271	0.180
84	-86.447	45.581	80.990	85.551	7.313	74.230	-7.244	85.396	0.182
85	-89.050	46.267	78.769	86.590	7.113	75.346	-7.462	86.431	0.183
86	-91.379	46.879	76.781	87.518	6.933	76.343	-7.657	87.357	0.185
87	-93.429	47.396	75.032	88.299	6.775	77.184	-7.829	88.135	0.186
88	-94.557	47.666	74.082	88.708	6.690	77.625	-7.923	88.543	0.187
89	-94.898	47.743	73.790	88.823	6.663	77.750	-7.952	88.657	0.187
90	-95.228	47.812	73.509	88.925	6.638	77.862	-7.980	88.759	0.187
91	-95.547	47.872	73.237	89.014	6.613	77.960	-8.006	88.848	0.187
92	-95.854	47.923	72.975	89.088	6.590	78.043	-8.032	88.921	0.188
93	-96.150	47.963	72.723	89.145	6.567	78.108	-8.057	88.978	0.188
94	-96.434	47.991	72.481	89.182	6.545	78.154	-8.081	89.015	0.188
95	-96.706	48.005	72.249	89.198	6.524	78.177	-8.103	89.030	0.188
96	-96.967	48.004	72.027	89.188	6.504	78.175	-8.125	89.020	0.188
97	-97.216	47.985	71.814	89.150	6.485	78.144	-8.146	88.982	0.189
98	-97.453	47.946	71.612	89.079	6.467	78.080	-8.166	88.911	0.189
99	-97.679	47.882	71.420	88.970	6.449	77.976	-8.185	88.801	0.189
100	-97.893	47.791	71.237	88.816	6.433	77.828	-8.203	88.648	0.190
101	-98.095	47.668	71.065	88.610	6.417	77.628	-8.220	88.442	0.190
102	-98.286	47.508	70.903	88.345	6.403	77.367	-8.236	88.177	0.190
103	-98.466	47.304	70.751	88.008	6.389	77.035	-8.251	87.841	0.191
104	-98.633	47.049	70.608	87.589	6.376	76.620	-8.265	87.422	0.191
105	-98.790	46.734	70.476	87.073	6.364	76.107	-8.278	86.906	0.192
106	-98.935	46.348	70.353	86.442	6.353	75.478	-8.290	86.276	0.193
107	-99.069	45.880	70.241	85.677	6.343	74.715	-8.301	85.511	0.194
108	-99.191	45.313	70.138	84.753	6.333	73.792	-8.312	84.588	0.194
109	-99.303	44.631	70.045	83.642	6.325	72.682	-8.321	83.479	0.196
110	-99.403	43.813	69.961	82.311	6.318	71.350	-8.329	82.149	0.197
111	-99.493	42.834	69.887	80.719	6.311	69.756	-8.337	80.559	0.198
112	-99.573	41.666	69.822	78.819	6.305	67.853	-8.344	78.662	0.200
113	-99.642	40.273	69.767	76.556	6.300	65.585	-8.349	76.402	0.202
114	-99.701	38.615	69.720	73.864	6.296	62.885	-8.354	73.714	0.204
115	-99.752	36.645	69.682	70.665	6.292	59.676	-8.359	70.520	0.205
116	-99.793	34.305	69.652	66.868	6.290	55.866	-8.362	66.730	0.207
117	-99.826	31.530	69.629	62.368	6.288	51.346	-8.365	62.239	0.207
118	-99.851	28.243	69.614	57.042	6.286	45.994	-8.367	56.926	0.204
119	-99.869	24.359	69.605	50.757	6.285	39.668	-8.368	50.659	0.193
120 *	-99.882	19.882	69.601	43.527	6.285	32.378	-8.369	43.457	0.161
121 *	-99.890	15.306	69.601	36.160	6.285	24.927	-8.370	36.131	0.080
122 *	-99.894	11.326	69.603	29.786	6.285	18.444	-8.370	29.809	0.078

123 *	-99.896	8.320	69.604	25.010	6.285	13.549	-8.371	25.090	0.320
124 *	-99.896	6.432	69.604	22.036	6.285	10.475	-8.371	22.165	0.580
125 *	-99.896	5.542	69.605	20.643	6.285	9.025	-8.371	20.799	0.750
126 *	-99.894	5.278	69.605	20.233	6.285	8.596	-8.371	20.398	0.809
127 *	-99.893	5.268	69.606	20.217	6.285	8.579	-8.370	20.382	0.812
128 *	-99.892	5.306	69.606	20.275	6.286	8.640	-8.370	20.440	0.803
129 *	-99.891	5.326	69.607	20.306	6.286	8.673	-8.370	20.470	0.799
130 *	-99.890	5.322	69.607	20.301	6.286	8.667	-8.370	20.465	0.800
131 *	-99.890	5.307	69.607	20.277	6.286	8.642	-8.370	20.442	0.803
132 *	-99.890	5.290	69.608	20.251	6.286	8.615	-8.370	20.416	0.807
133 *	-99.889	5.277	69.608	20.230	6.286	8.593	-8.370	20.395	0.810
134 *	-99.889	5.268	69.608	20.217	6.286	8.579	-8.370	20.382	0.812
135 *	-99.889	5.263	69.608	20.209	6.286	8.571	-8.370	20.375	0.813
136 *	-99.889	5.261	69.608	20.206	6.286	8.568	-8.370	20.372	0.813
137 *	-99.889	5.260	69.608	20.205	6.286	8.567	-8.370	20.371	0.813
138 *	-99.889	5.260	69.608	20.205	6.286	8.567	-8.370	20.371	0.813
139 *	-99.889	5.261	69.608	20.205	6.286	8.567	-8.370	20.371	0.813
140 *	-99.889	5.260	69.608	20.205	6.286	8.567	-8.370	20.371	0.813
141 *	-99.889	5.260	69.608	20.205	6.286	8.566	-8.370	20.370	0.813
142 *	-99.889	5.260	69.608	20.204	6.286	8.566	-8.370	20.370	0.814
143 *	-99.889	5.259	69.608	20.203	6.286	8.565	-8.370	20.369	0.814
144 *	-99.889	5.259	69.608	20.203	6.286	8.564	-8.370	20.368	0.814
145 *	-99.889	5.258	69.608	20.201	6.286	8.563	-8.370	20.367	0.814
146 *	-99.889	5.257	69.608	20.200	6.286	8.562	-8.370	20.366	0.814
147 *	-99.889	5.257	69.608	20.199	6.286	8.560	-8.370	20.365	0.814
148 *	-99.889	5.255	69.608	20.196	6.286	8.558	-8.370	20.362	0.815
149 *	-99.889	5.252	69.608	20.193	6.286	8.554	-8.370	20.359	0.815
150 *	-99.889	5.250	69.608	20.188	6.286	8.549	-8.370	20.354	0.816
151 *	-99.889	5.246	69.608	20.183	6.286	8.543	-8.370	20.349	0.817
152 *	-99.889	5.241	69.608	20.175	6.286	8.535	-8.370	20.341	0.818
153 *	-99.889	5.232	69.608	20.161	6.286	8.520	-8.370	20.327	0.820
154 *	-99.889	5.204	69.609	20.117	6.286	8.474	-8.370	20.284	0.826
155 *	-99.889	5.086	69.609	19.935	6.286	8.283	-8.370	20.106	0.854
156 *	-99.889	4.562	69.609	19.121	6.286	7.429	-8.370	19.312	0.987
157 *	-99.882	2.076	69.613	15.730	6.286	3.381	-8.369	15.633	0.616
								Maximum =	0.987

From comparison above, it can be concluded that Orcaflex or DNV method will eventually give very close results in Von Mises stress calculation. For this example case, the deviations between those two methods are less than 1 %.

Appendix B

Model States[28]

OrcaFlex builds and analyses a mathematical model of the system being analyzed, the model being built up from a series of interconnected objects, such as Lines, Vessels and Buoys. For more details see Modeling and Analysis.

OrcaFlex works on the model by moving through a sequence of states, the current state being shown on the status bar.

The following diagram shows the sequence of states used and the actions, results etc. available in each state.

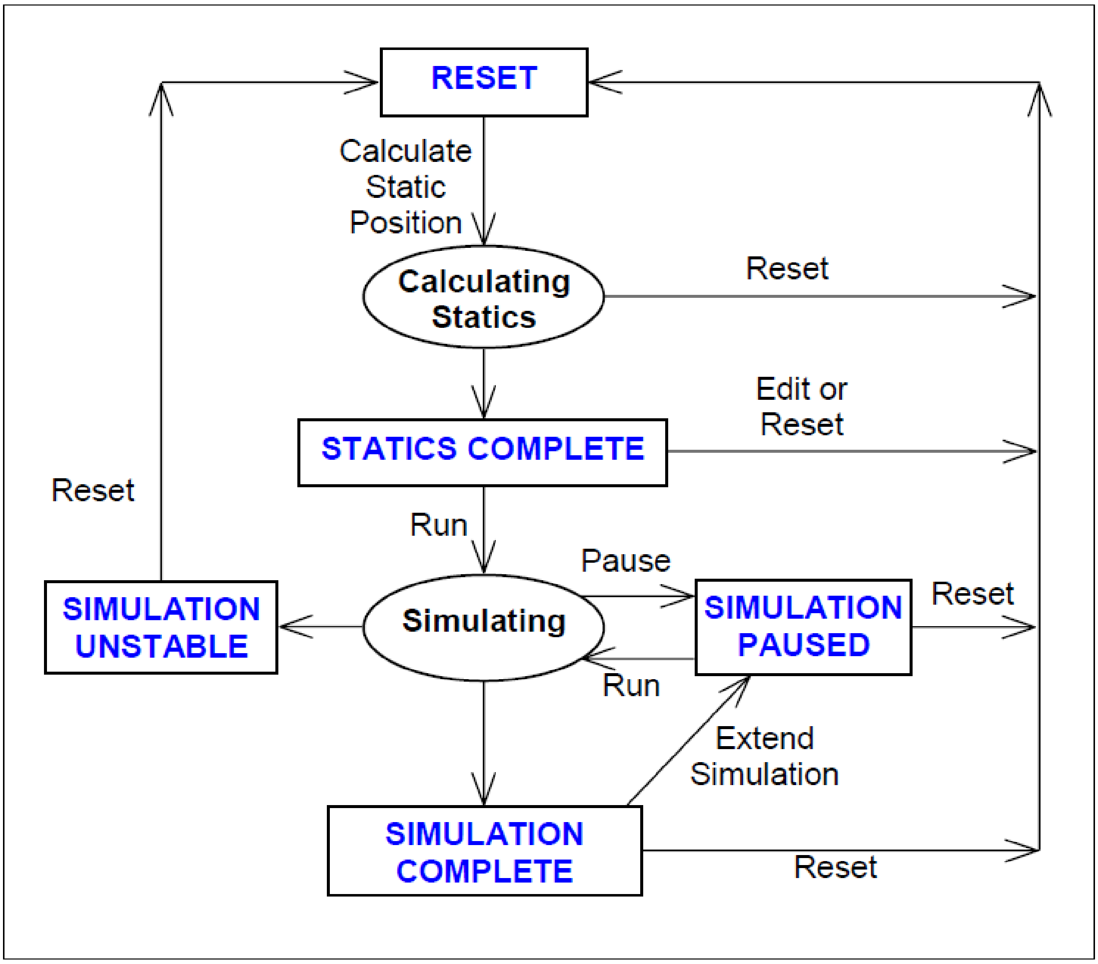

Figure B.1: Model States

The states used are as follows:

- **Reset**

The state in which OrcaFlex starts. In Reset state you can freely change the model and edit the data. No results areavailable.

- **Calculating Statics**

OrcaFlex is calculating the statics position of the model. You can abort the calculation by CLICKING the Reset button.

➢ **Statics Complete**

The statics calculation is complete and the static position results are available. You are allowed to make changes to the model when in this state but if you make any changes (except for very minor changes like colours used) then the model will be automatically reset and the statics results will be lost.

➢ **Simulating**

The dynamic simulation is running. The results of the simulation so far are available and you can examine the model data, but only make minor changes (e.g. colours used). You cannot store the simulation to a file while simulating - you must pause the simulation first.

➢ **Simulation Paused**

There is a simulation active, but it is paused. The results so far are available and you can examine the model data. You can also store the part-run simulation to a file.

➢ **Simulation Complete**

The simulation is complete. The simulation results are available and you can store the results to a simulation file for later examination. You must reset the model, by CLICKING on the Reset button, before significant changes to the model can be made.

You can use the Extend Simulation facility if you wish to simulate for a further period of time.

➢ **Simulation Unstable**

The simulation has become unstable. The simulation results are available and you can store the results to a simulation file for later examination. This allows you to try and understand why the simulation has become unstable. You may also want to examine the results up until the point at which the simulation became unstable. However, please treat these results with caution - because the simulation eventually went unstable this indicates that the dynamic simulation may not have converged at earlier simulation times.

You must reset the model, by CLICKING on the Reset button, before significant changes to the model can be made.

Using Model States[28]

To illustrate how model states work, here is an example of a typical working pattern:

1. In **Reset** state, open a new model from a data file or use the current model as the starting point for a new model.

2. In **Reset** state, add or remove objects and edit the model data as required for the new model. It is generally best to use a very simple model in the early

stages of design and only add more features when the simple model is satisfactory.

3. Run a static analysis (to get to **Statics Complete** state) and examine the static position results. Make any corrections to the model that is needed - this will automatically reset the model. Steps (2) and (3) are repeated as required

4. Run a simulation and monitor the results during the simulation (in **Simulating** state).

5. If further changes to the model are needed then **Reset** the model and edit the model accordingly. Steps (2) to (5) are repeated as required.

6. Finalize the model, perhaps improving the discretisation (for example by reducing the time step sizes or increasing the number of segments used for Lines). Run a final complete simulation (to reach **Simulation Complete** state) and generate reports using the results.

Appendix C

Static results

Brief OrcaFlex results for the static analysis can be seen in below diagrams:

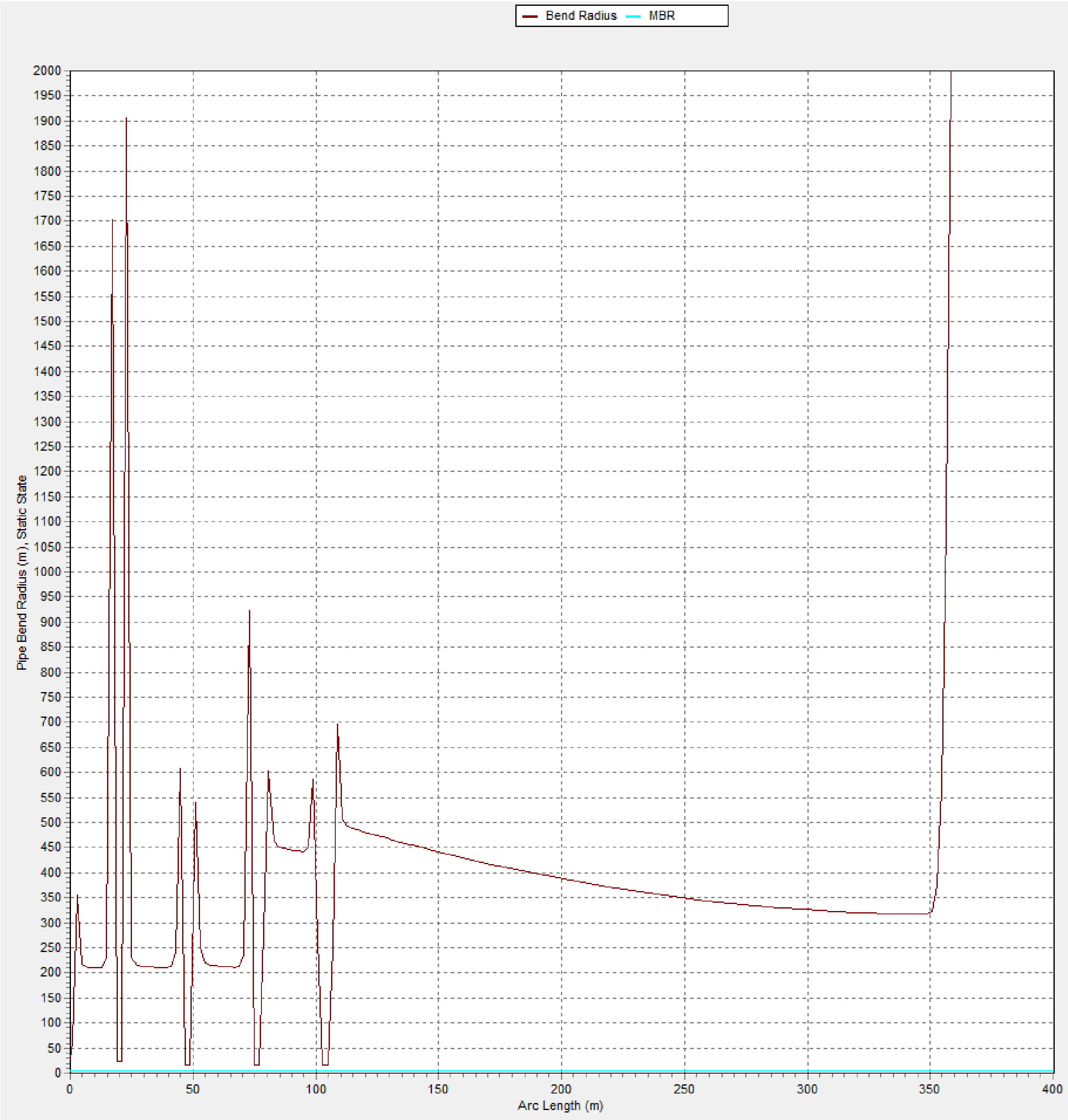

Diagram C.1 Pipe bending Radius vs Arc Length, Static State (Case 0°)

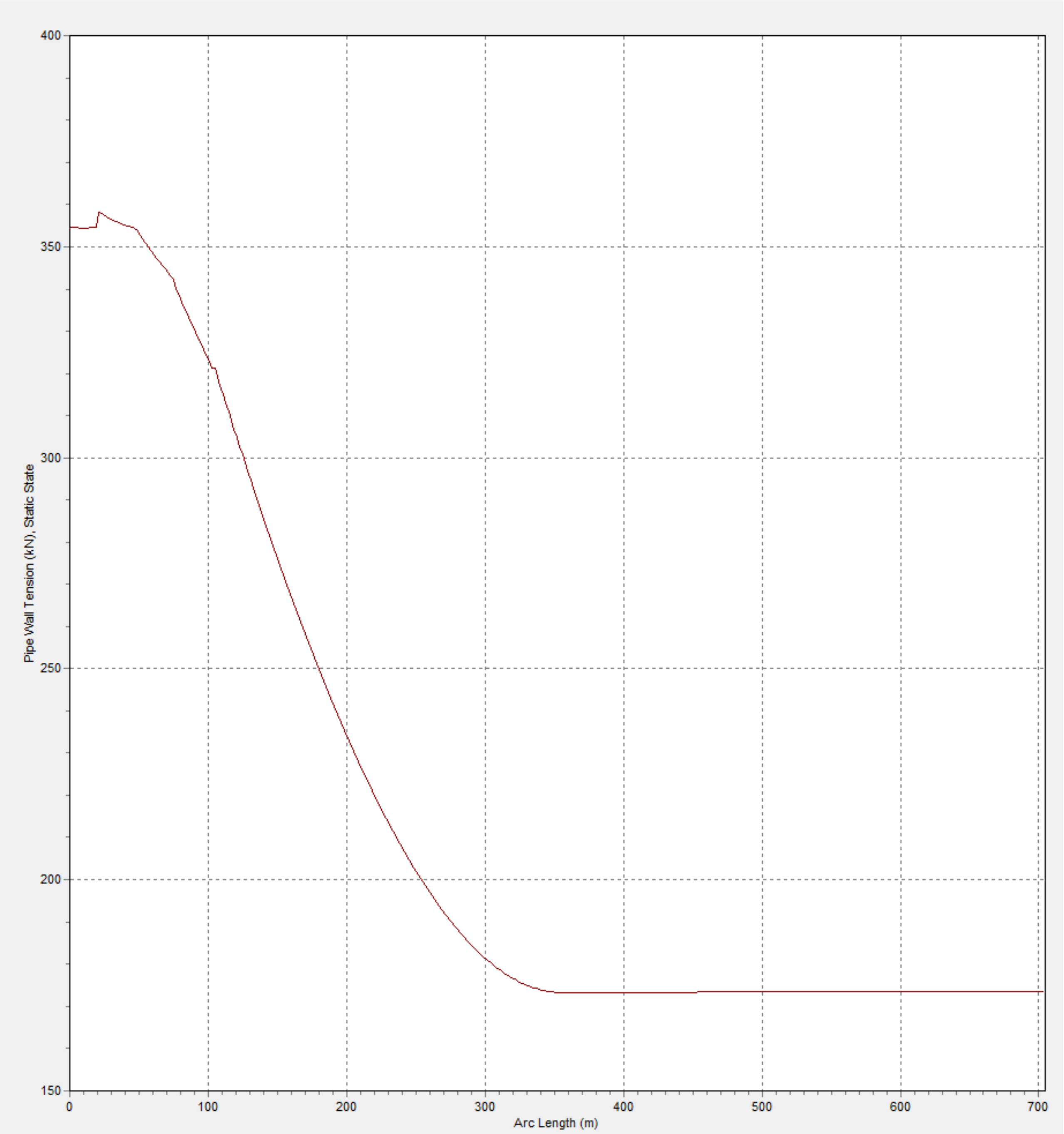

Diagram C.2 Wall Tension vs Arc Length, Static State (Case 0°)

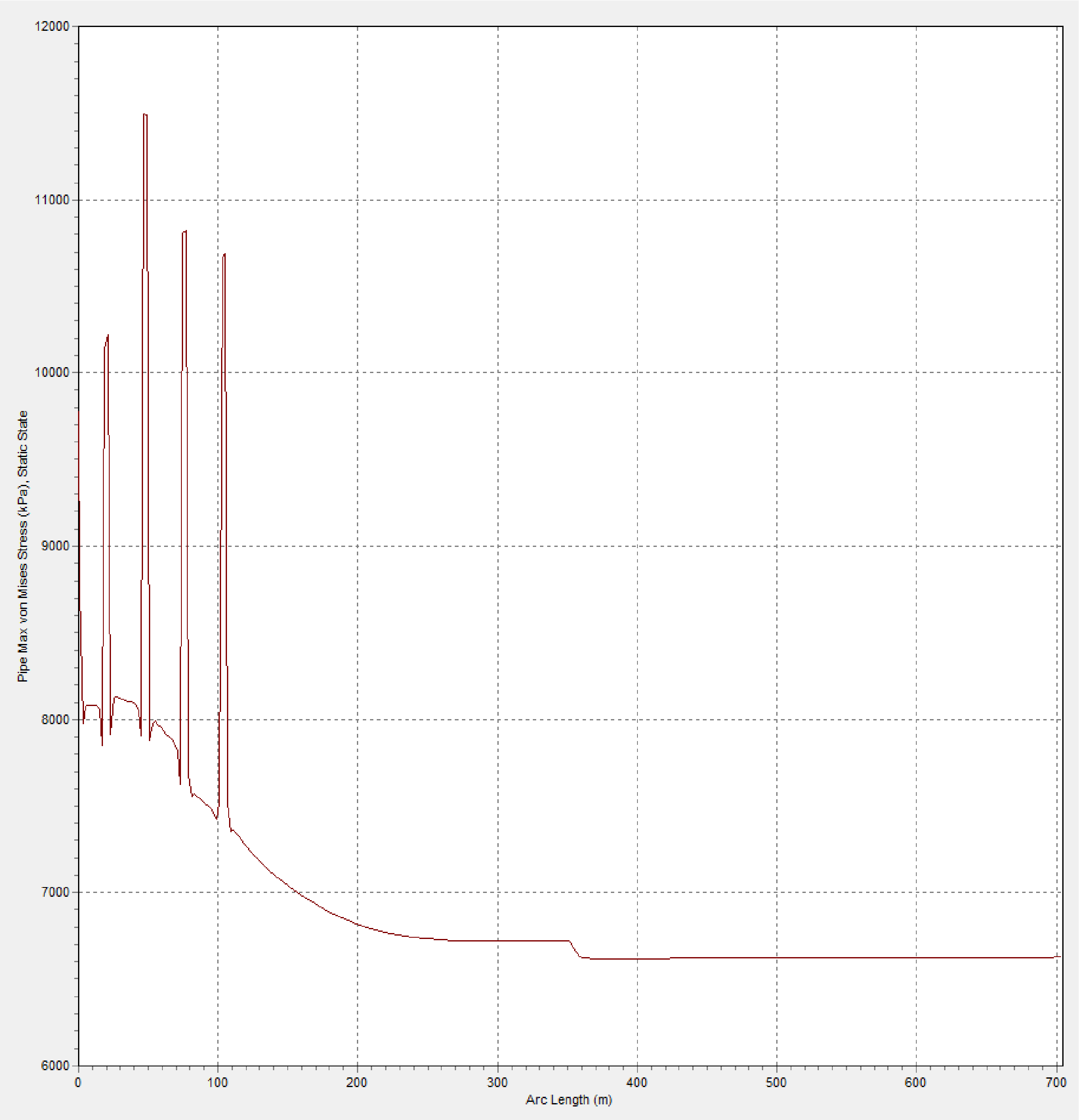

Diagram C.3 Max von Mises Stress vs Arc Length, Static State (Case 0°)

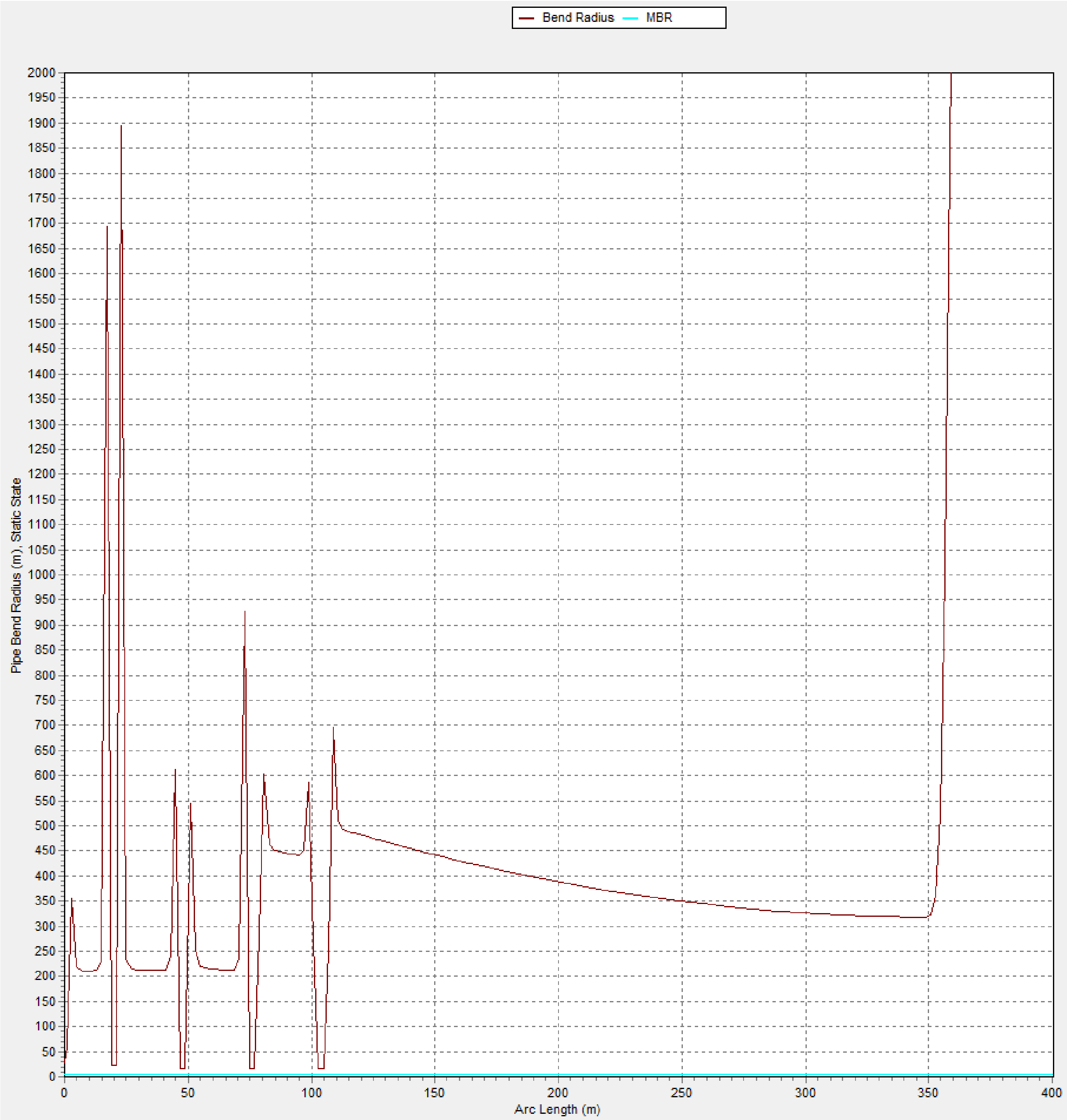

Diagram C.4 Pipe bending Radius vs Arc Length, Static State (Case 30°)

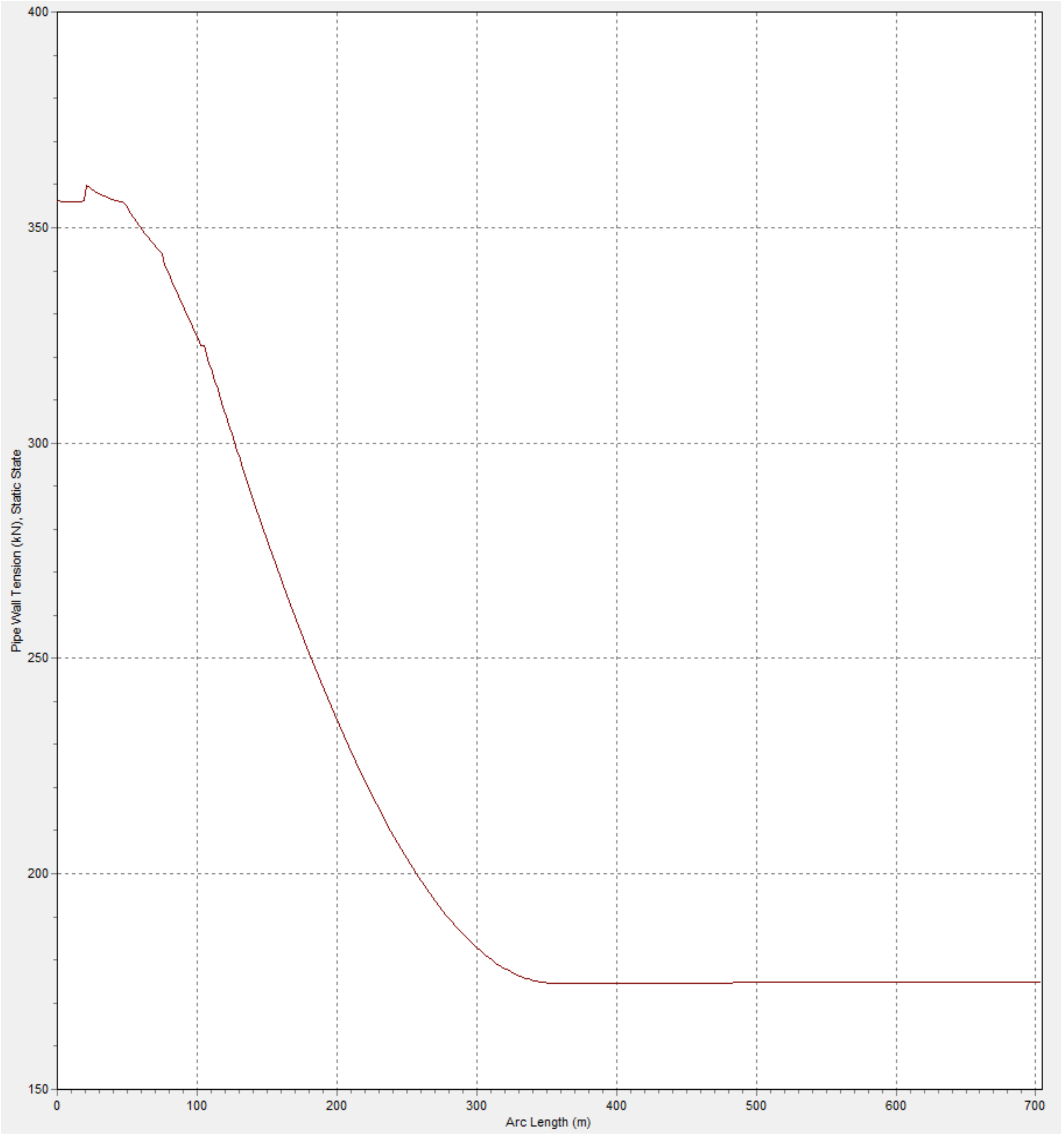

Diagram C.5 Wall Tension vs Arc Length, Static State (Case 30°)

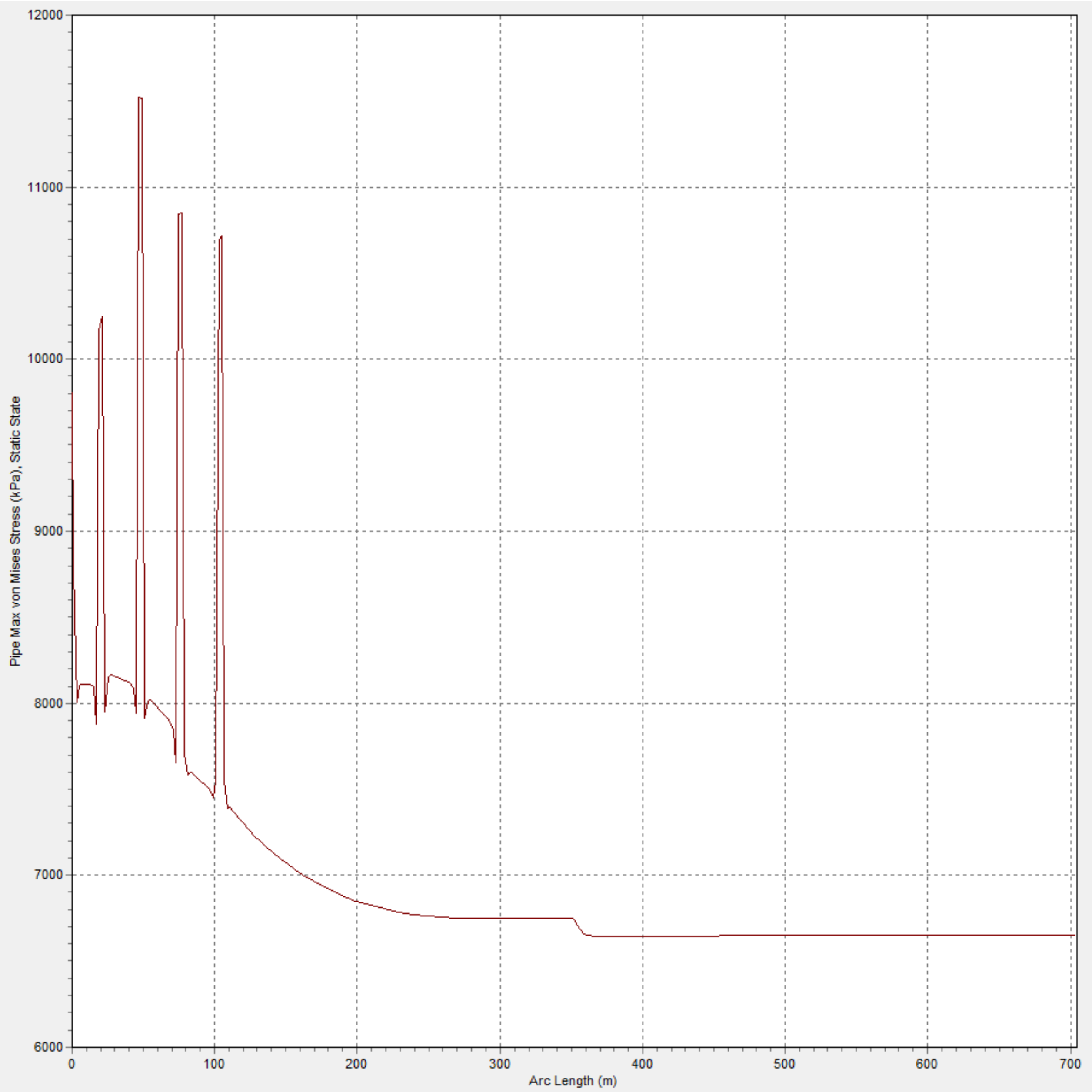

Diagram C.6 Max von Mises Stress vs Arc Length, Static State (Case 30°)

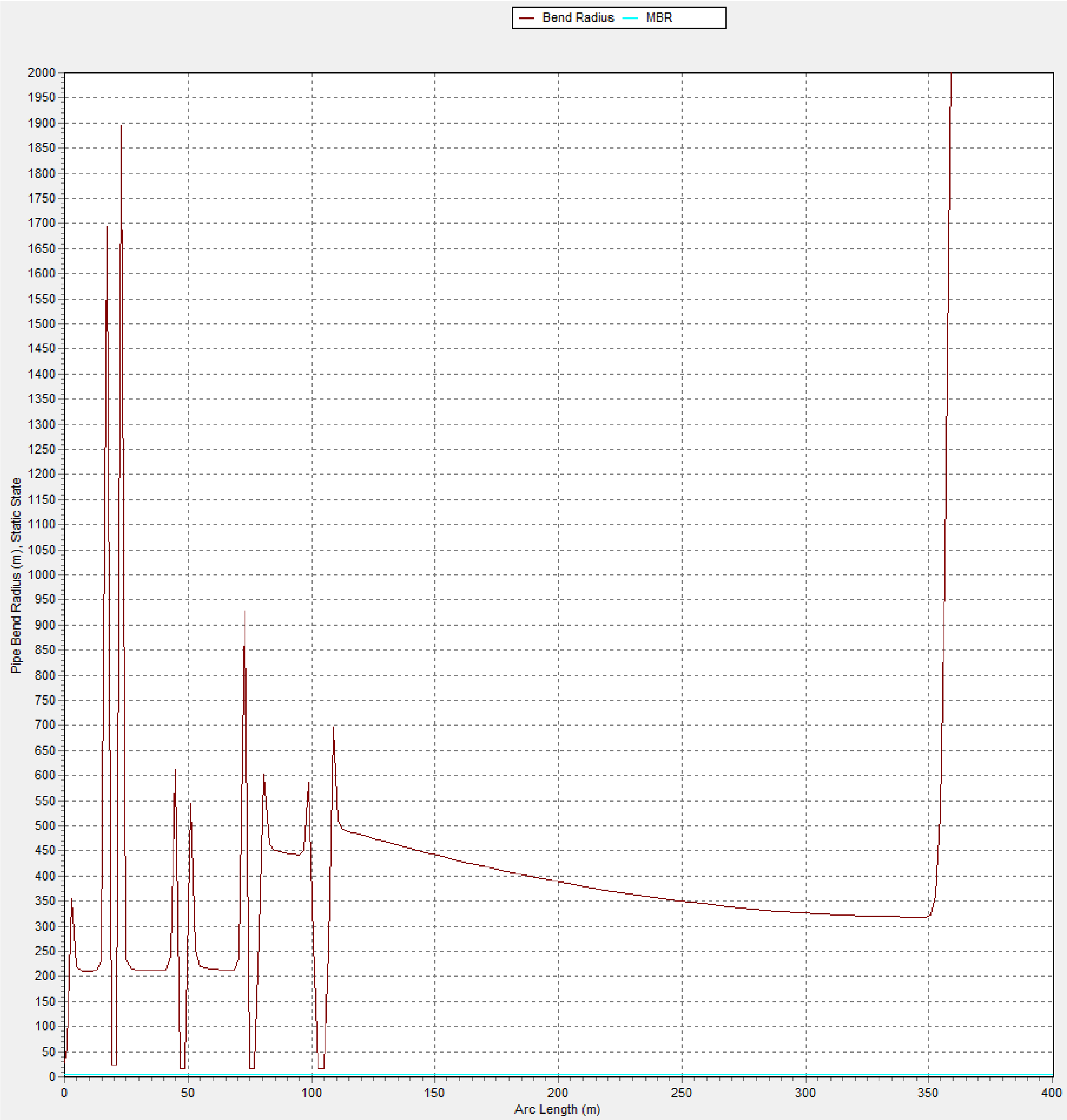

Diagram C.7 Pipe bending Radius vs Arc Length, Static State (Case 60°)

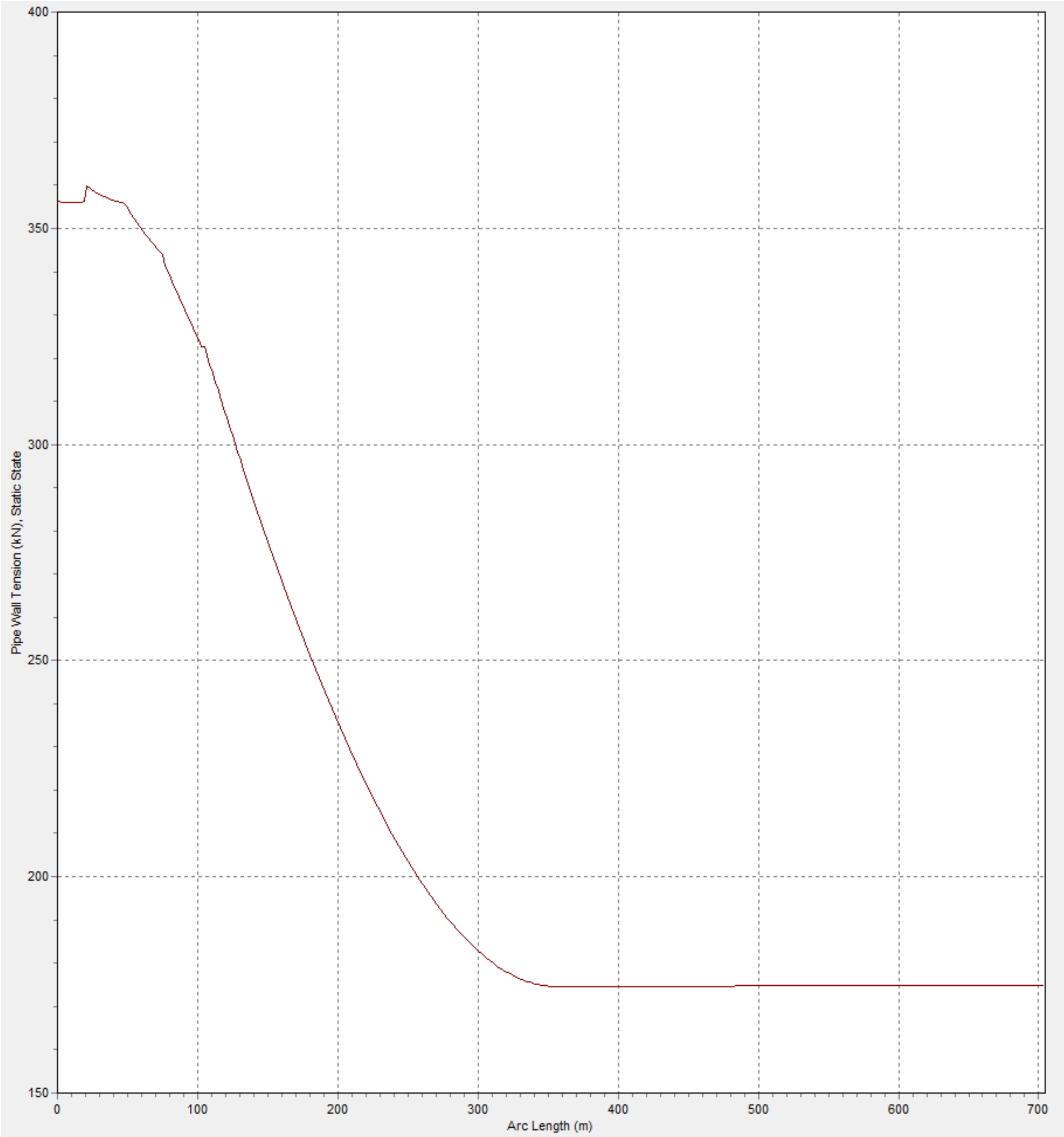

Diagram C.8 wall Tension vs Arc Length, Static State (Case 60°)

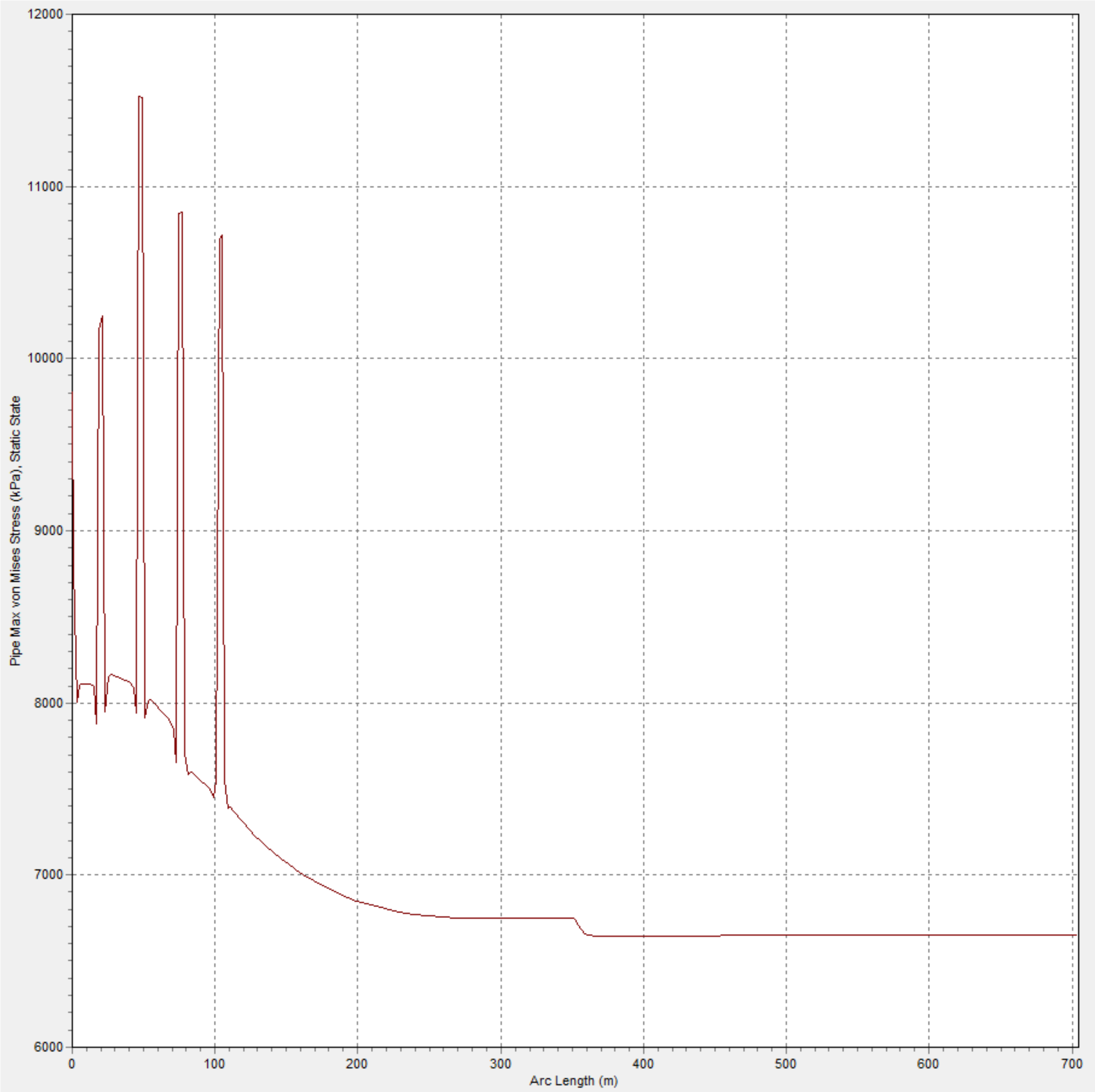

Diagram C.9 Max von Mises Stress vs Arc Length, Static State (Case 60°)

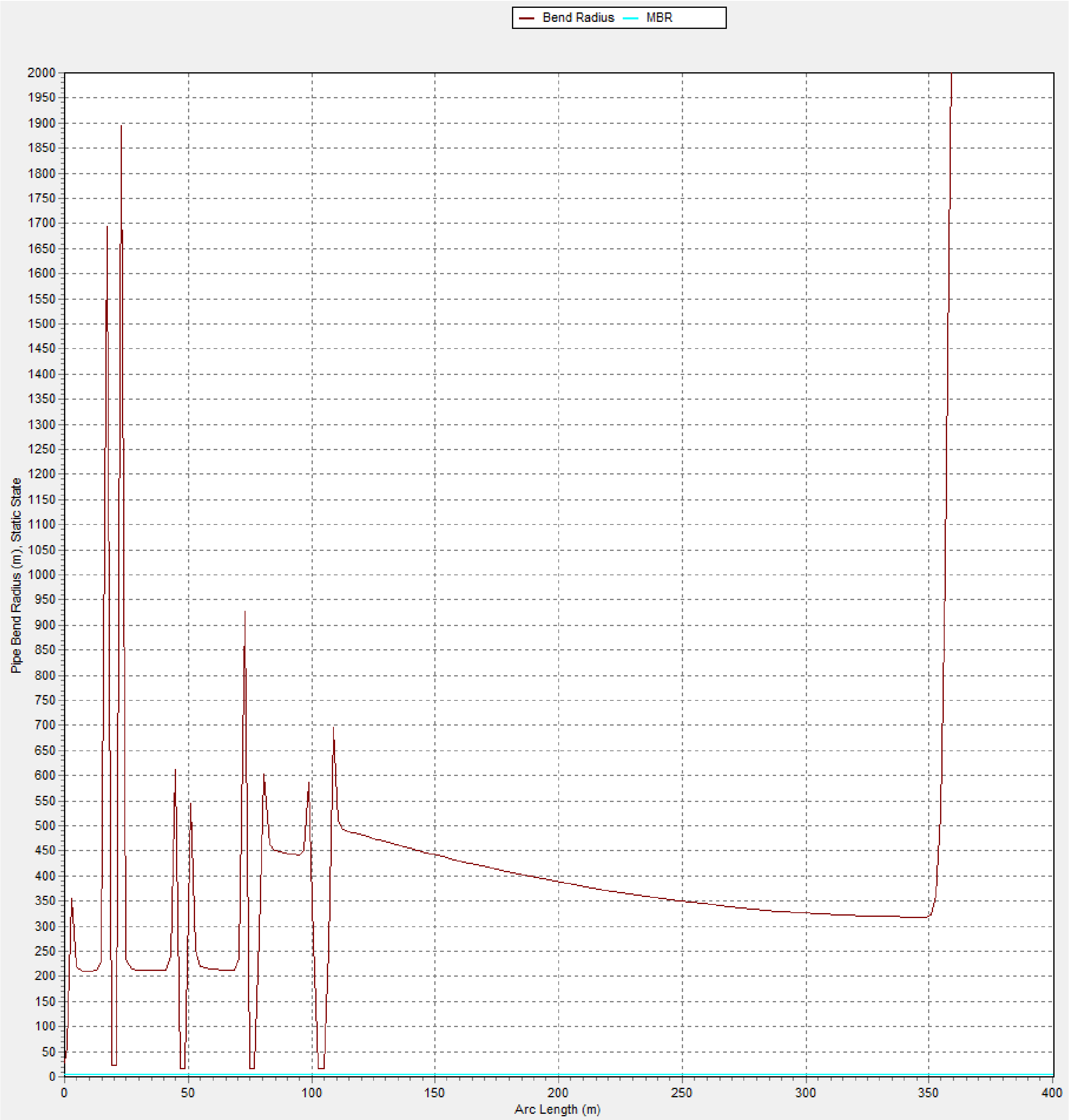

Diagram C.10 Pipe bending Radius vs Arc Length, Static State (Case 120°)

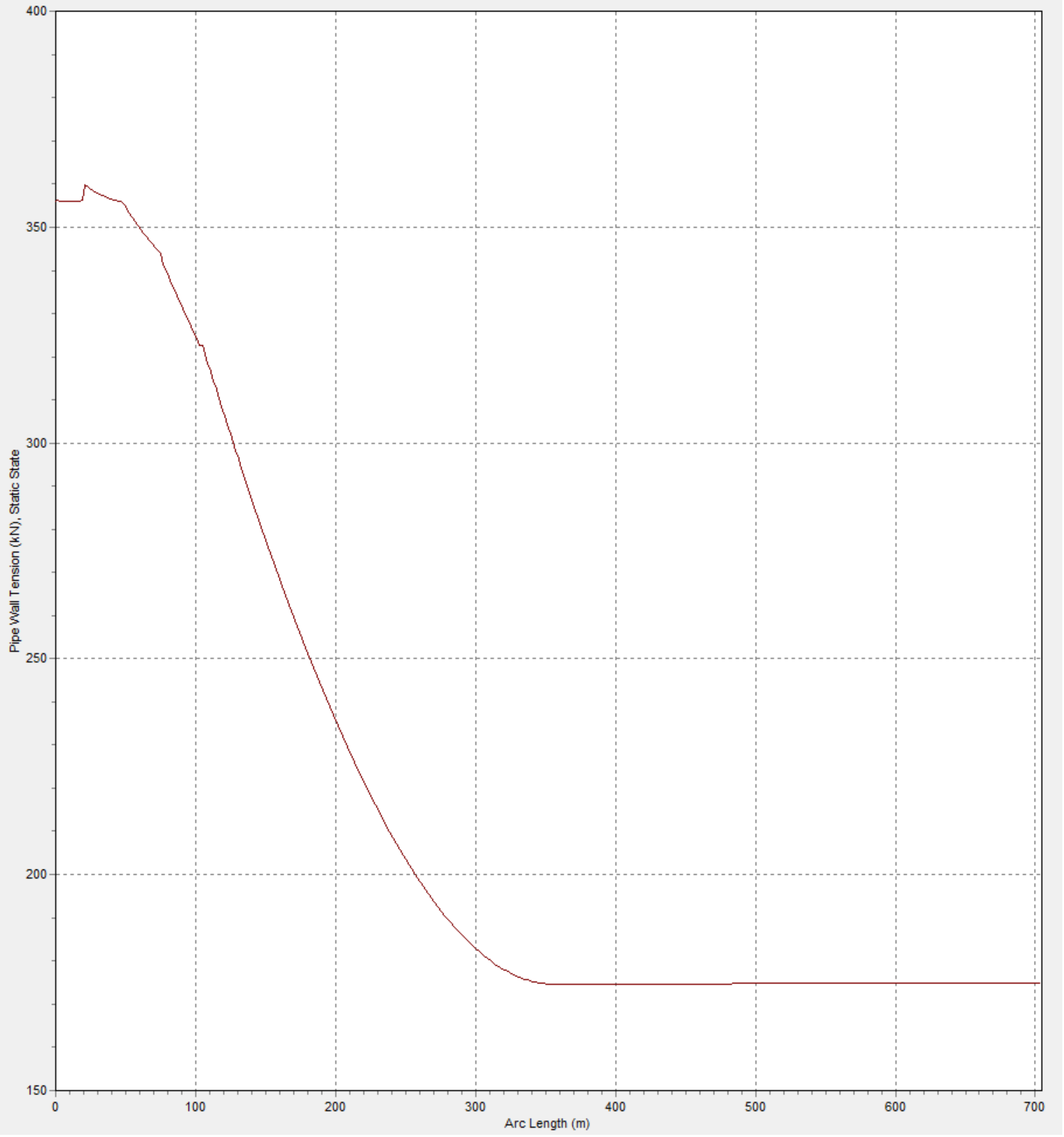

Diagram C.11 Wall Tension vs Arc Length, Static State (Case 120°)

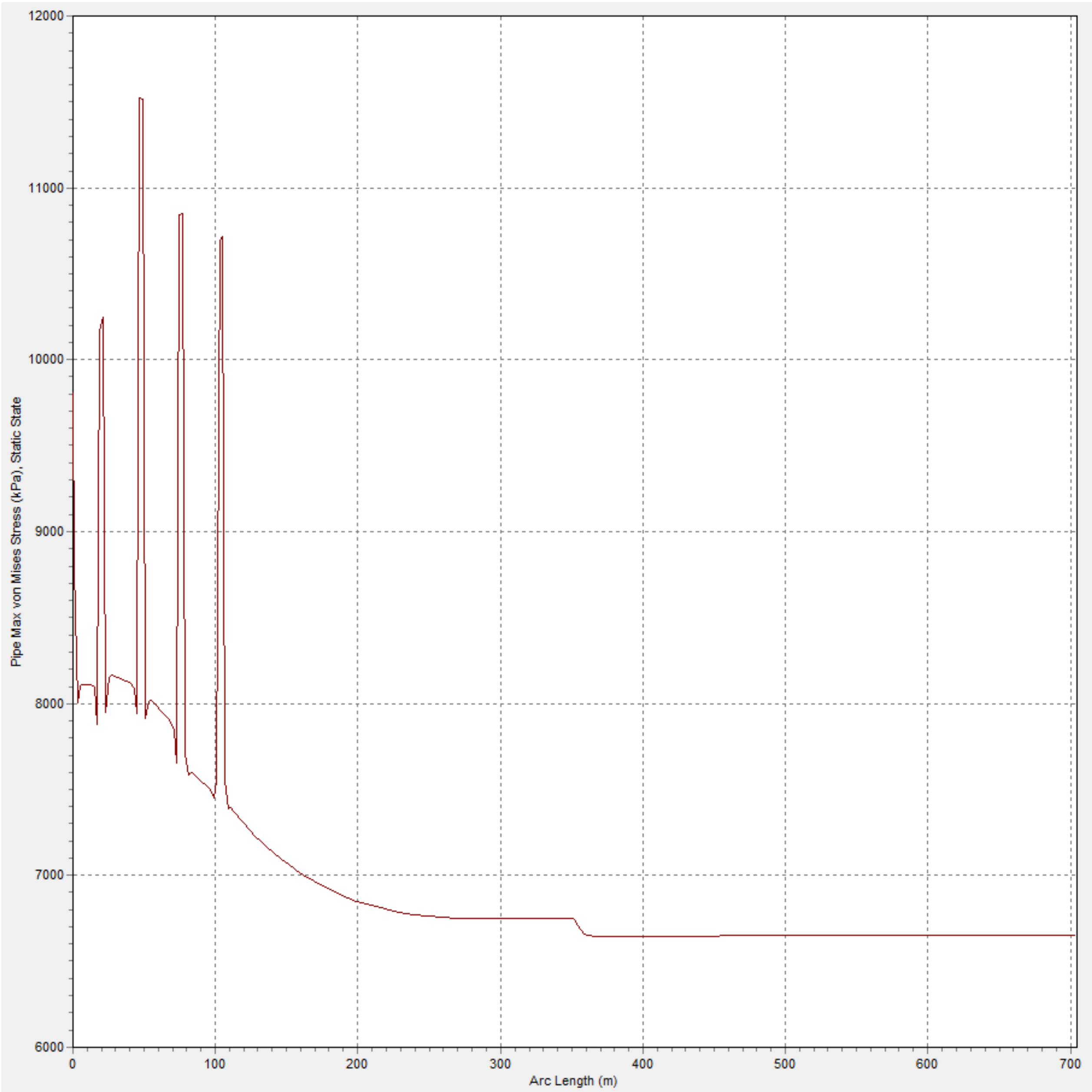

Diagram C.12 Max von Mises Stress vs Arc Length, Static State (Case 120°)

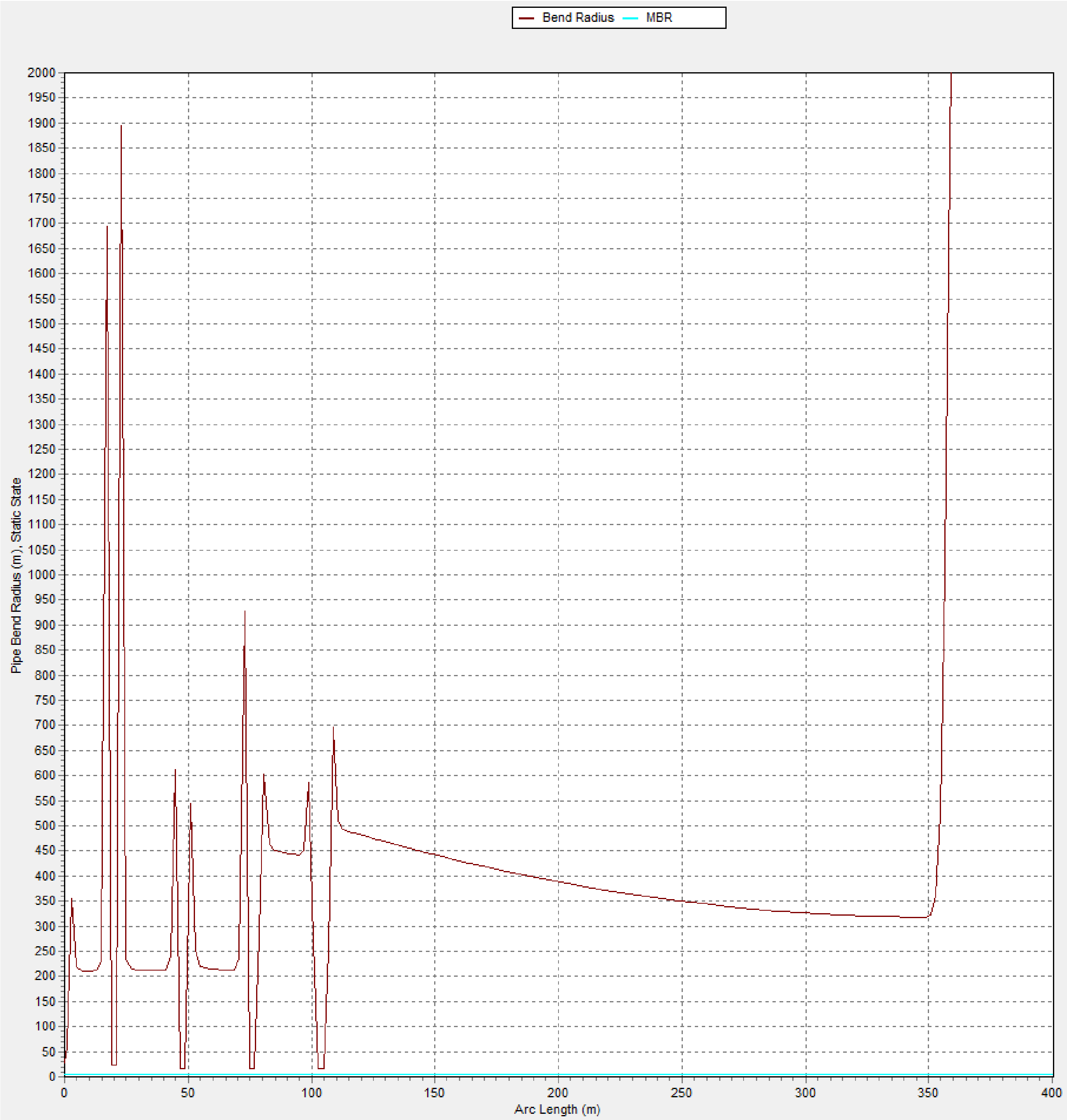

Diagram C.13 Pipe bending Radius vs Arc Length, Static State (Case 150°)

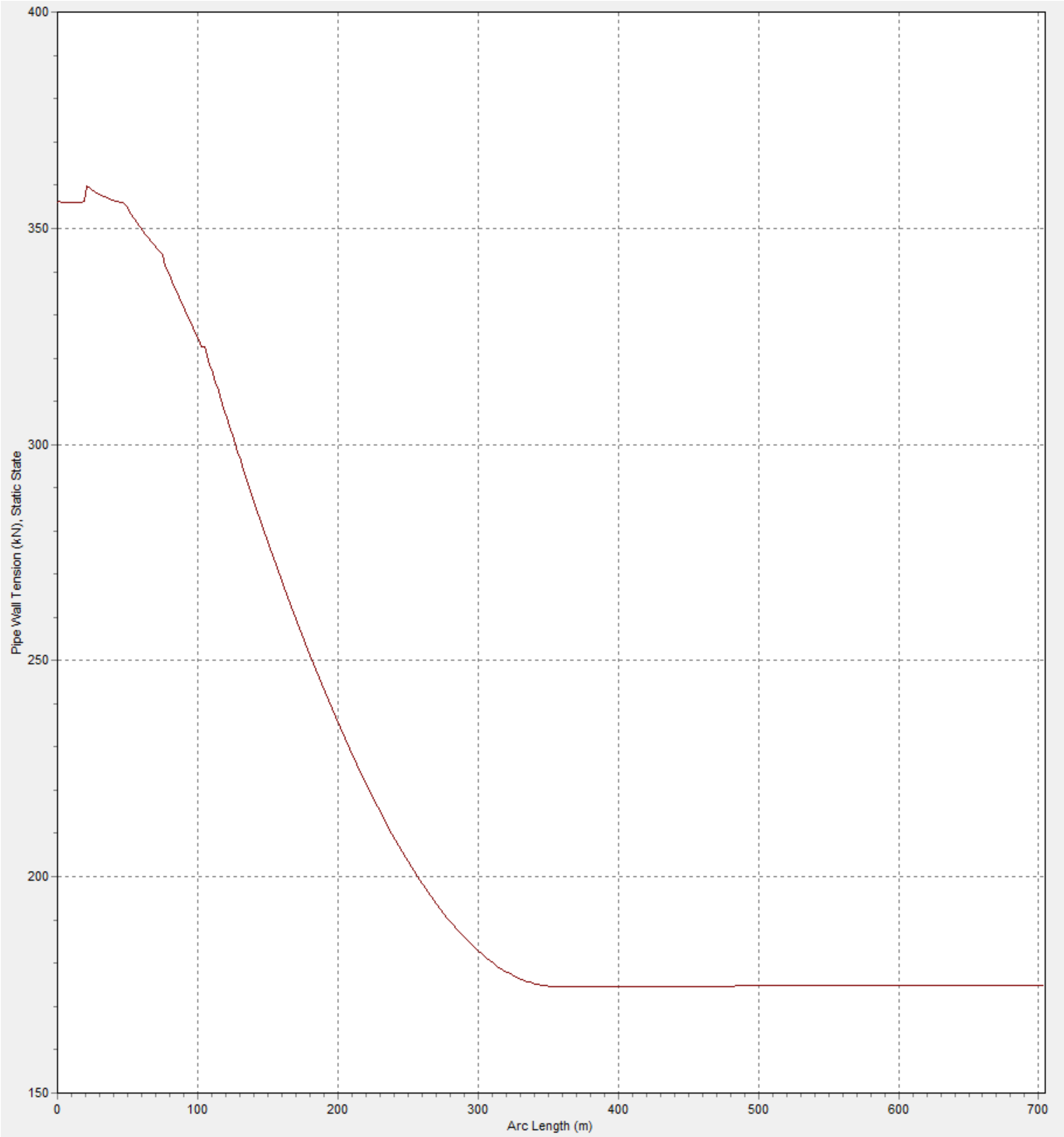

Diagram C.14 Wall Tension vs Arc Length, Static State (Case 150°)

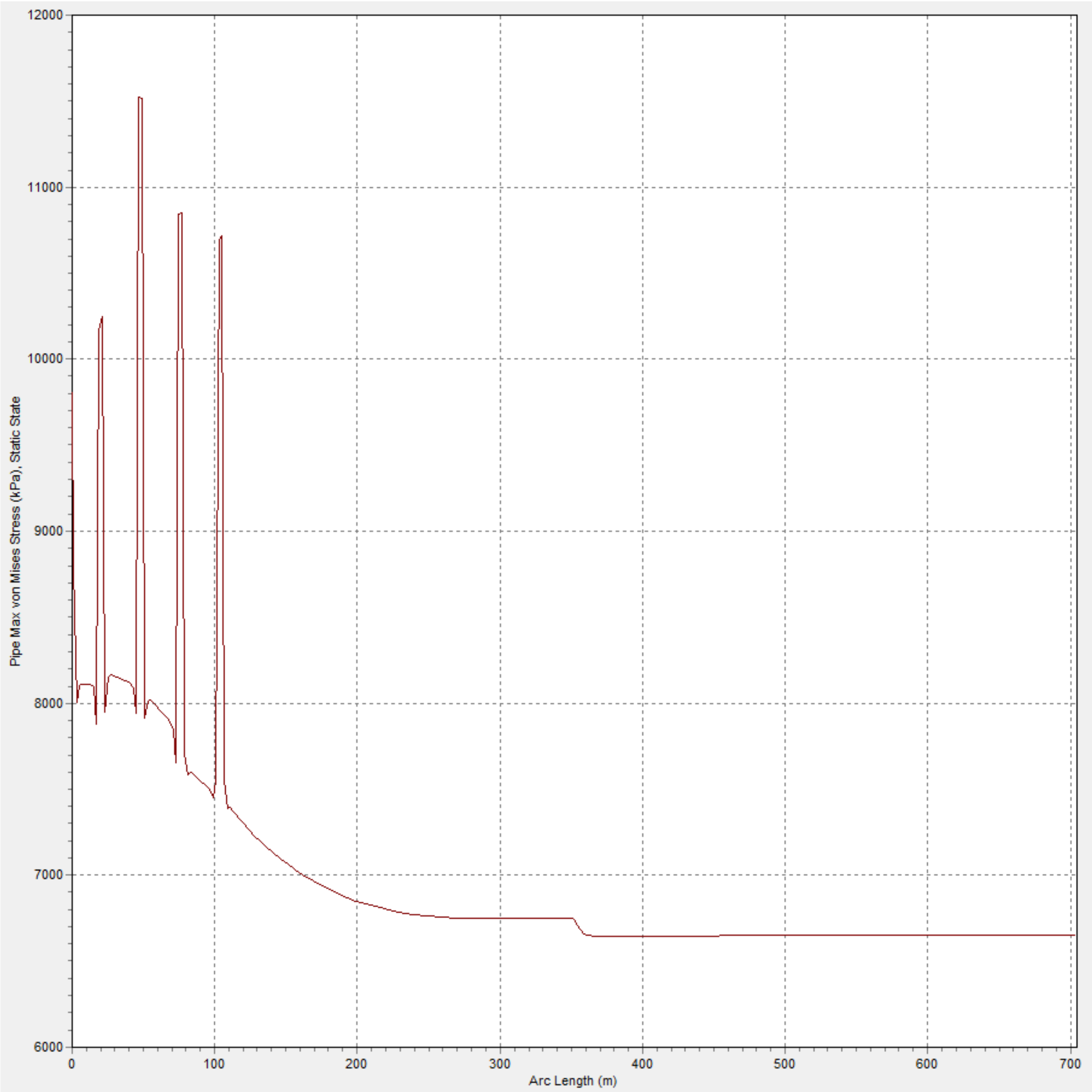

Diagram C.15 Max von Mises Stress vs Arc Length, Static State (Case 150°)

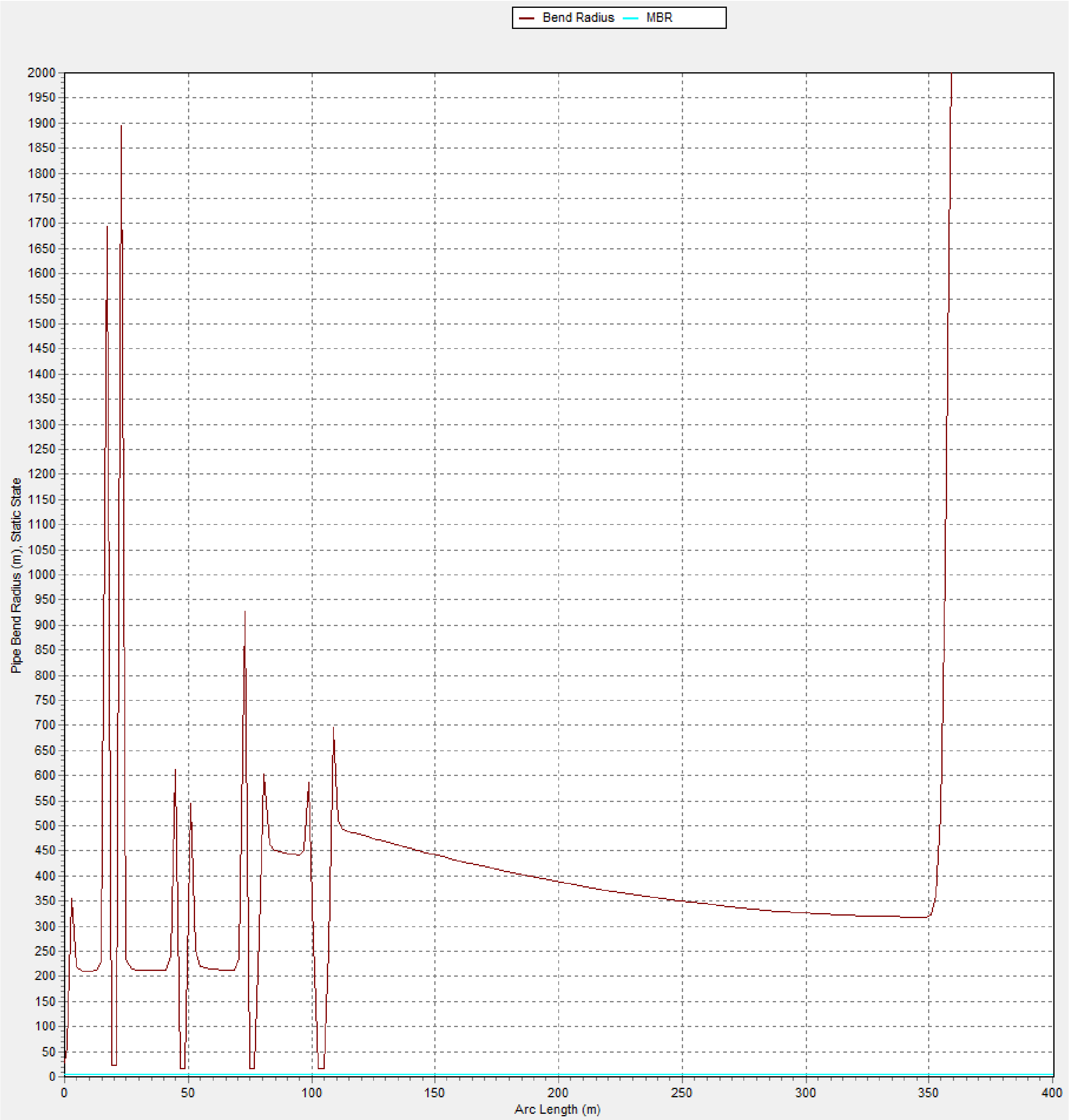

Diagram C.16 Pipe bending Radius vs Arc Length, Static State (Case 180°)

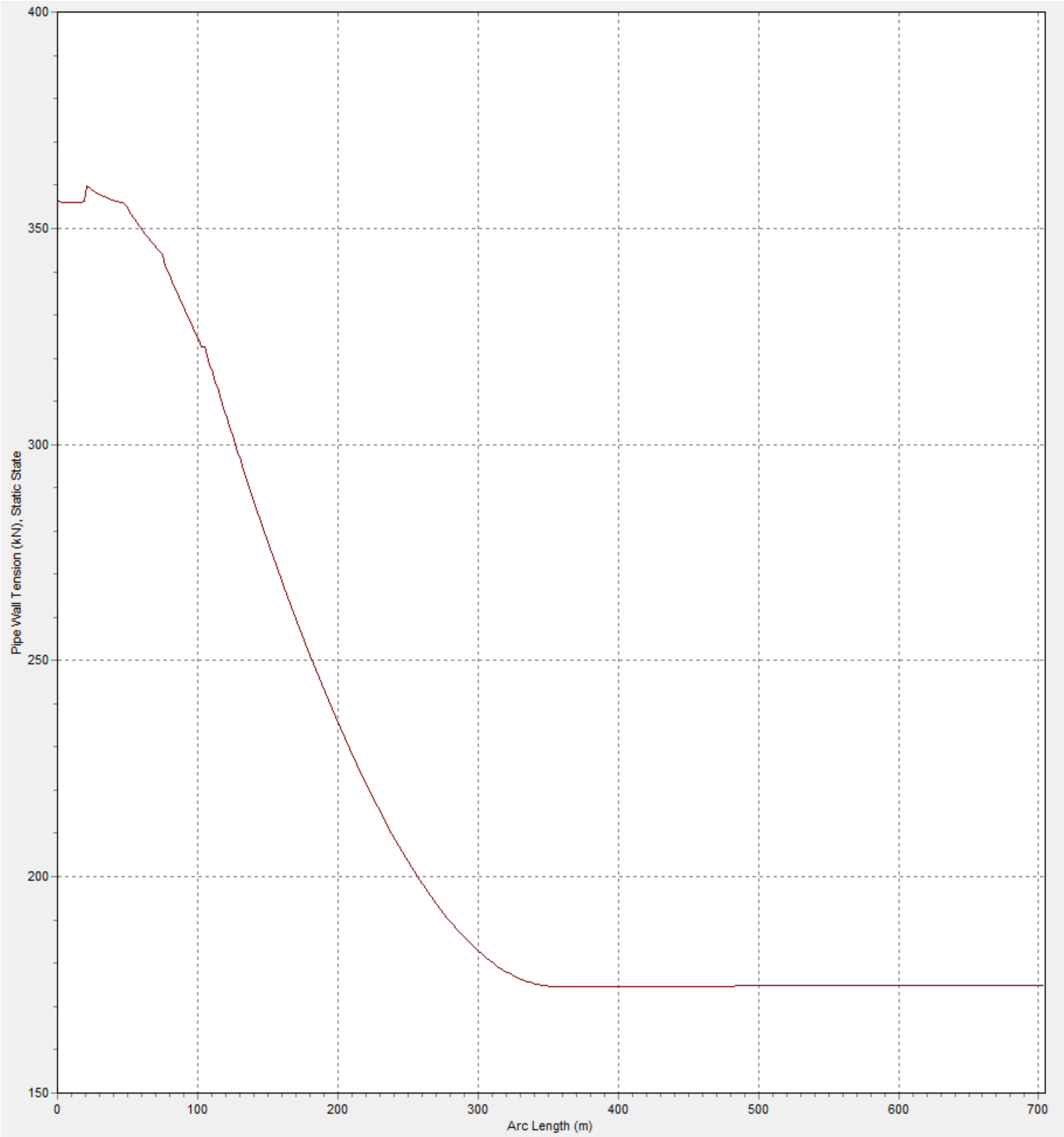

Diagram C.17 Wall Tension vs Arc Length, Static State (Case 180°)

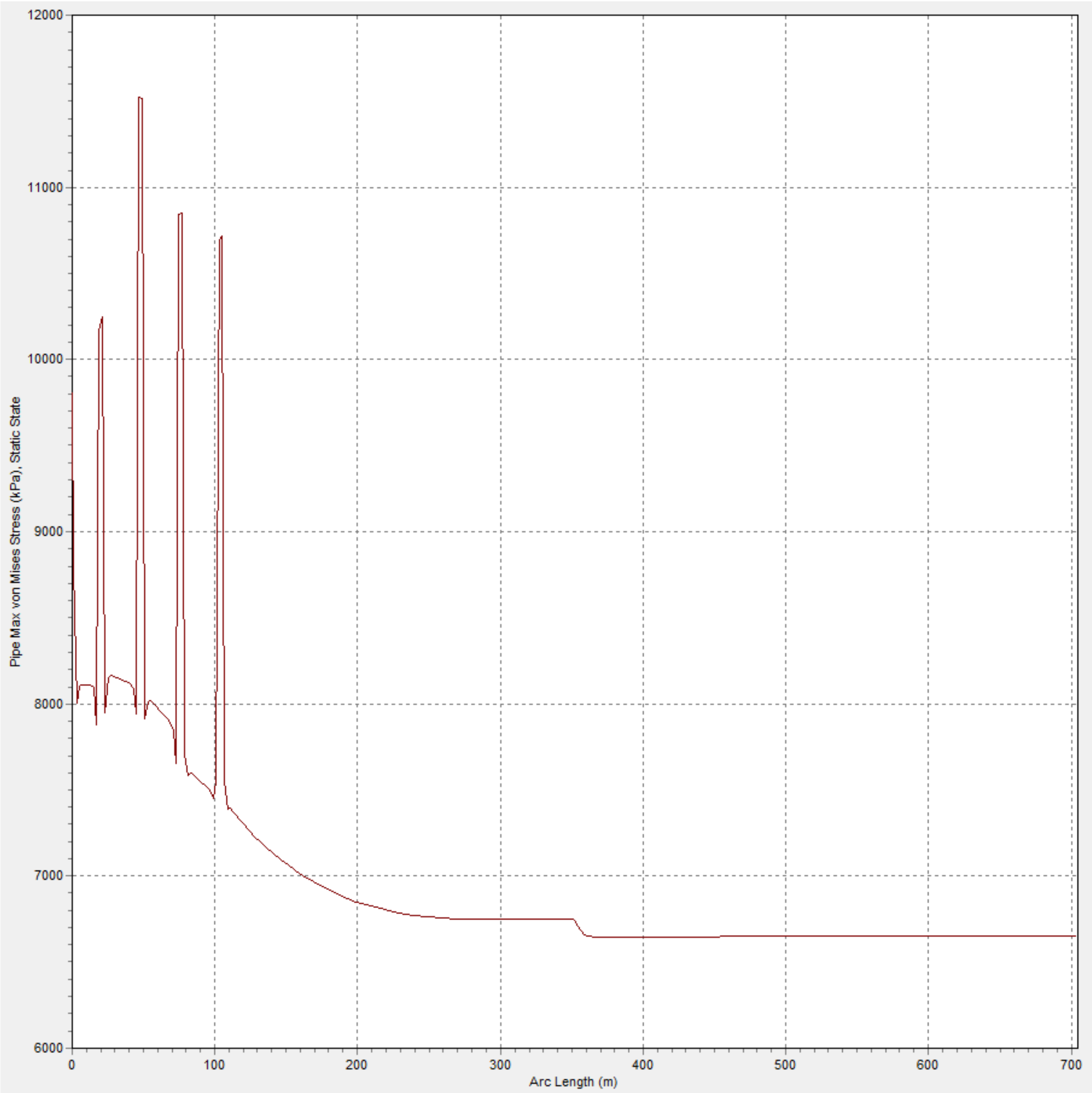

Diagram C.18 Max von Mises Stress vs Arc Length, Static State (Case 180°)

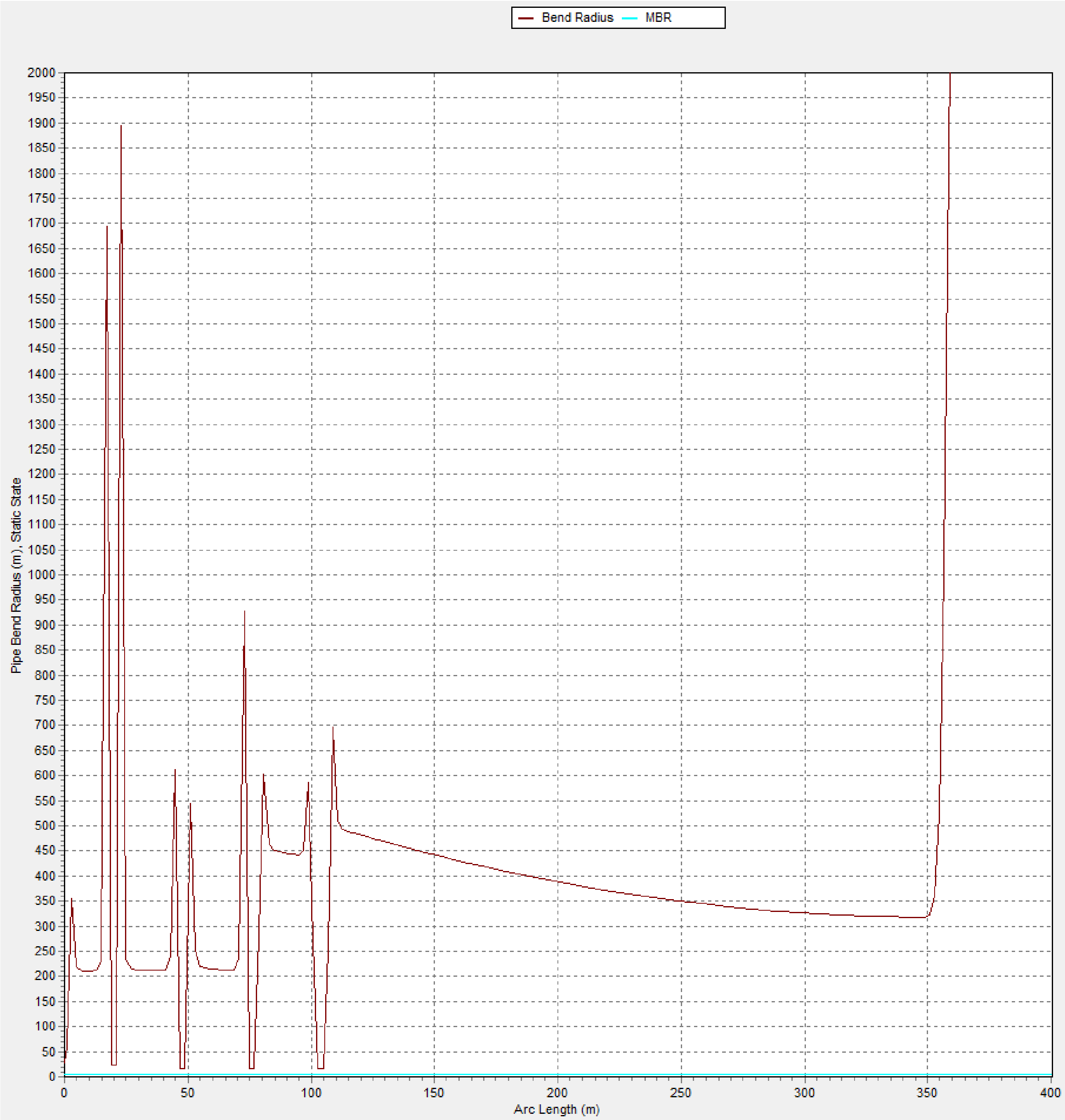

Diagram C.19 Pipe bending Radius vs Arc Length, Static State (No Current)

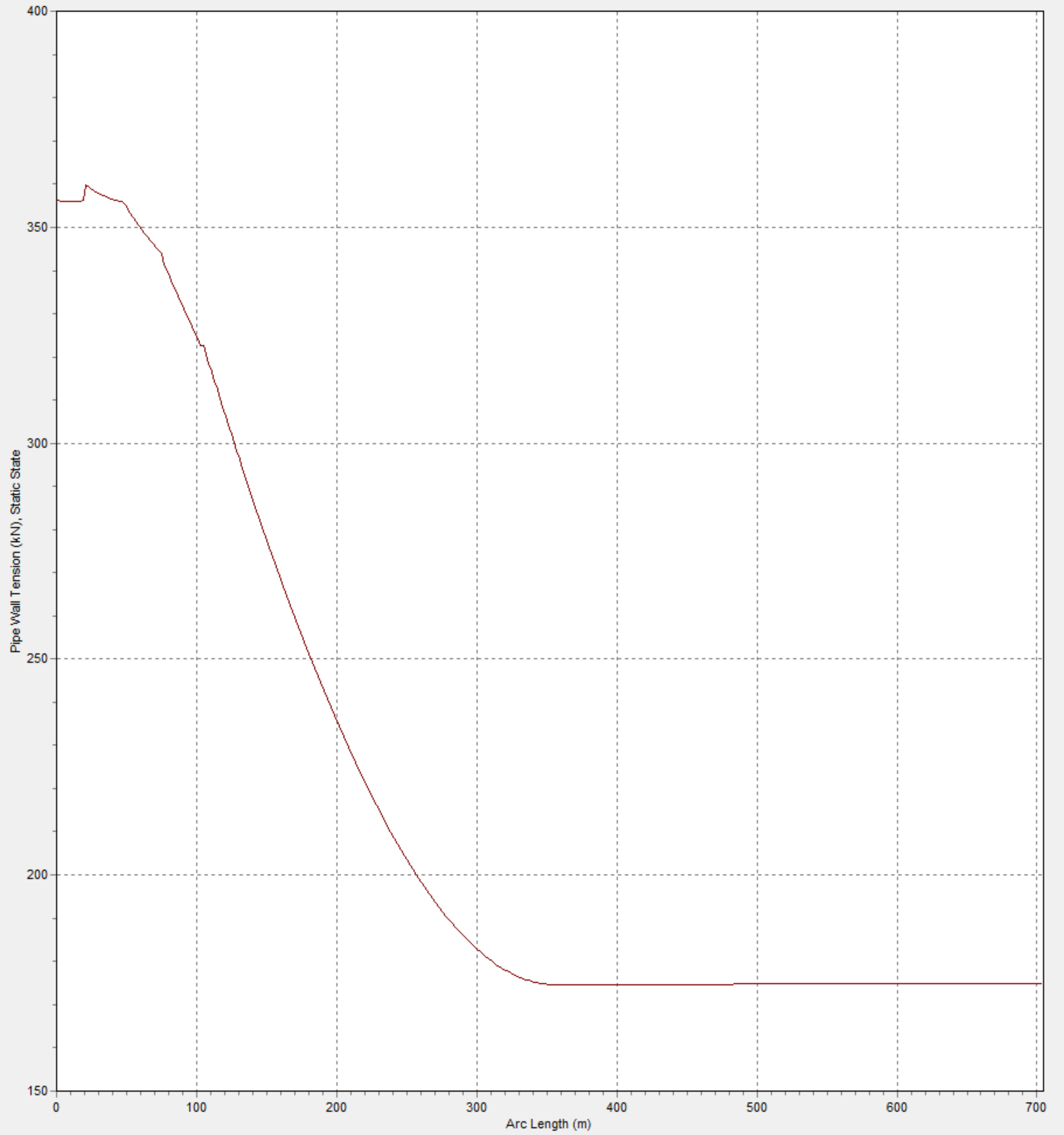

Diagram C.20 Wall Tension vs Arc Length, Static State (No Current)

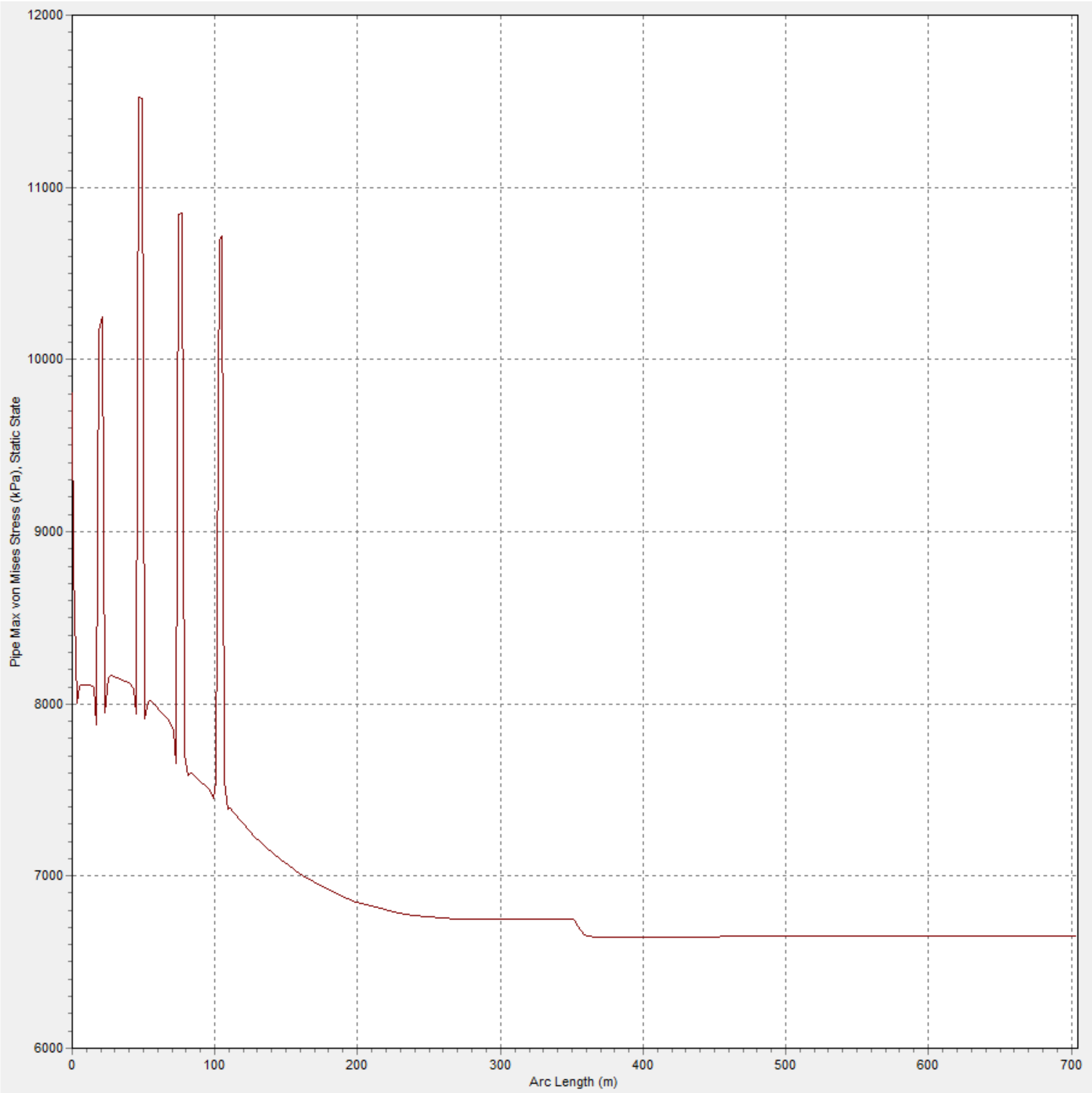

Diagram C.21 Max von Mises Stress vs Arc Length, Static State (No Current)

Appendix D

Dynamic Results

Brief OrcaFlex results for the dynamic analysis can be seen in below diagrams:

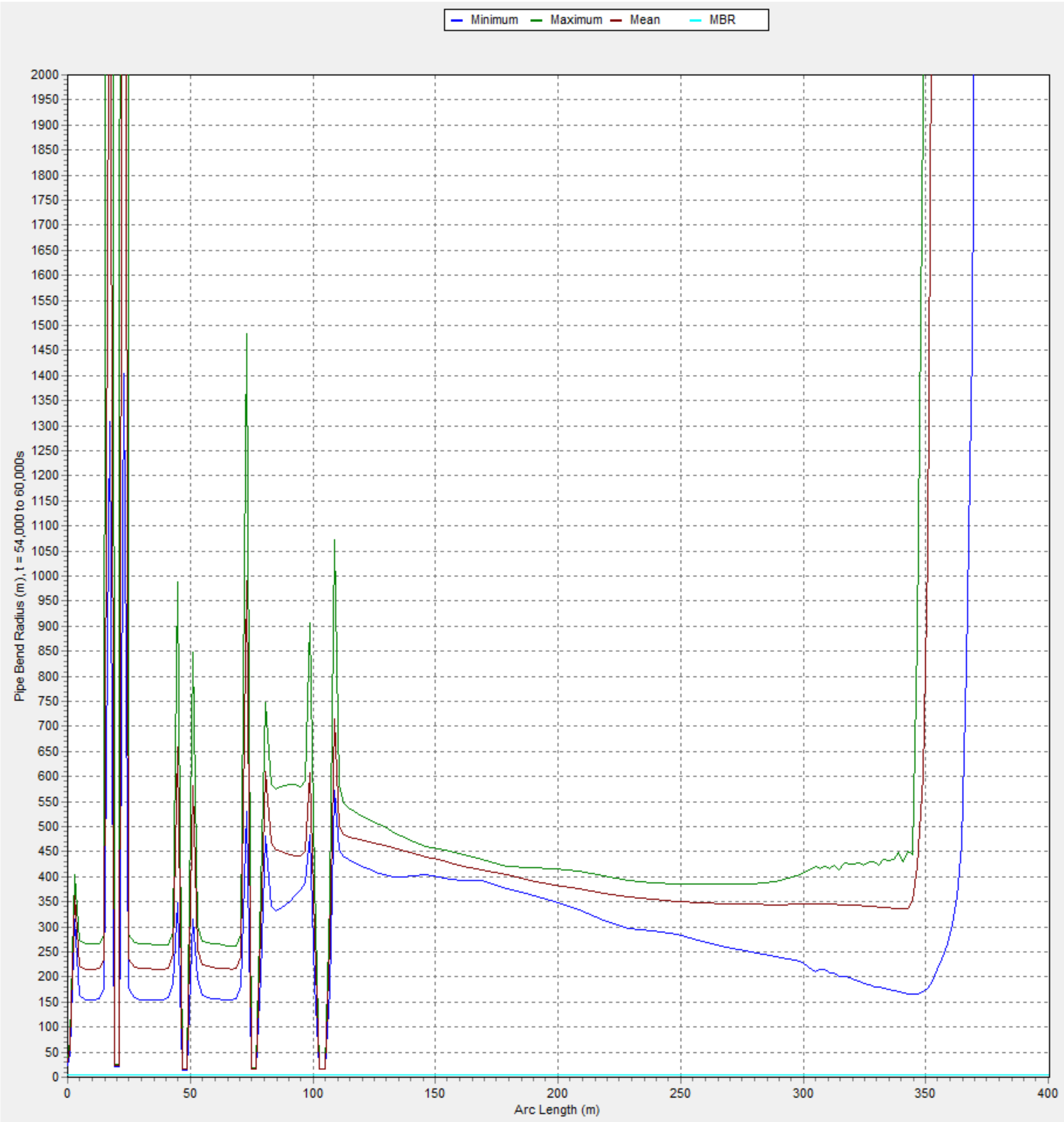

Diagram D.1 Pipe bending Radius vs Arc Length, Dynamic State (Case 0°)

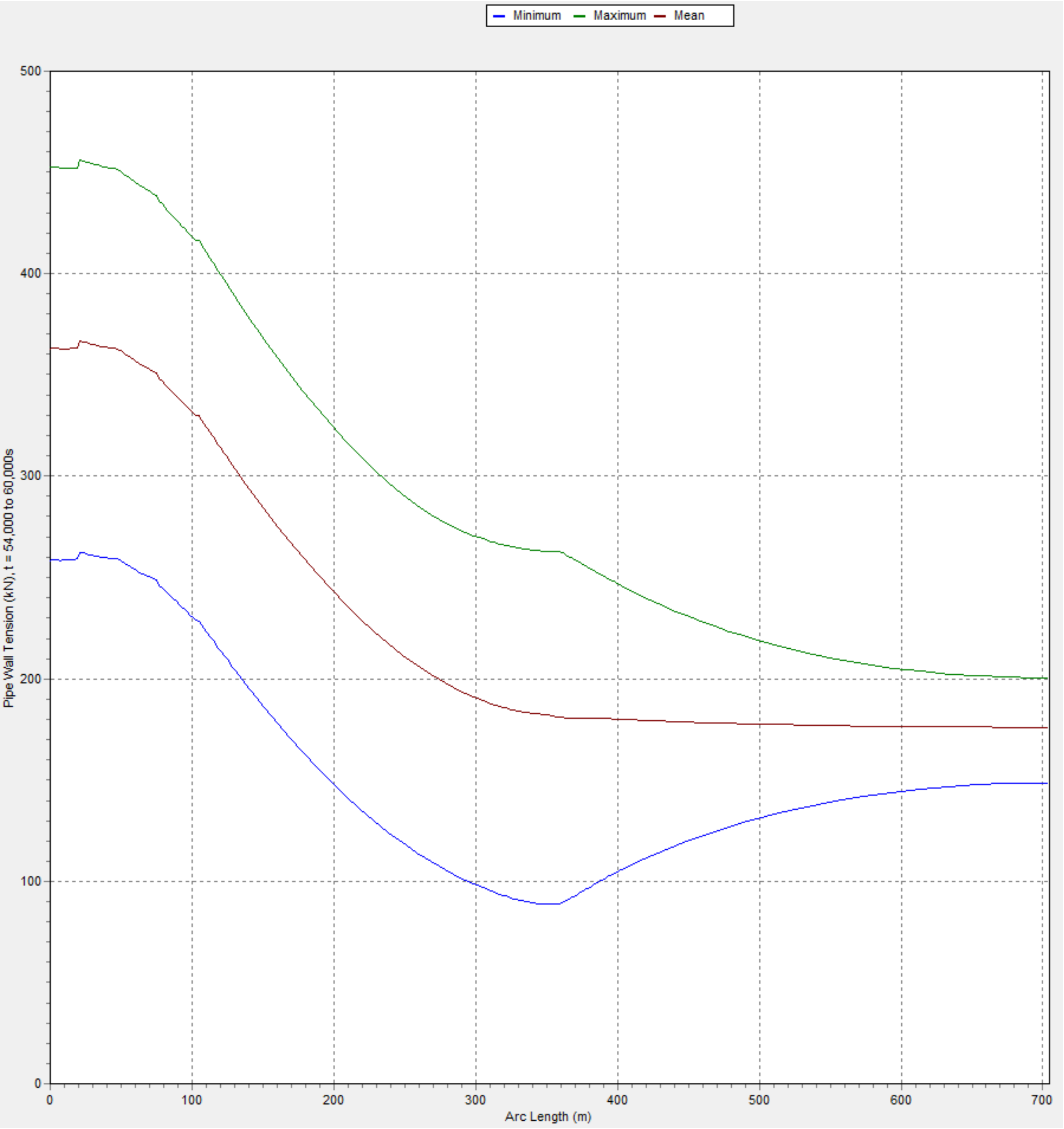

Diagram D.2 Wall Tension vs Arc Length, Dynamic State (Case 0°)

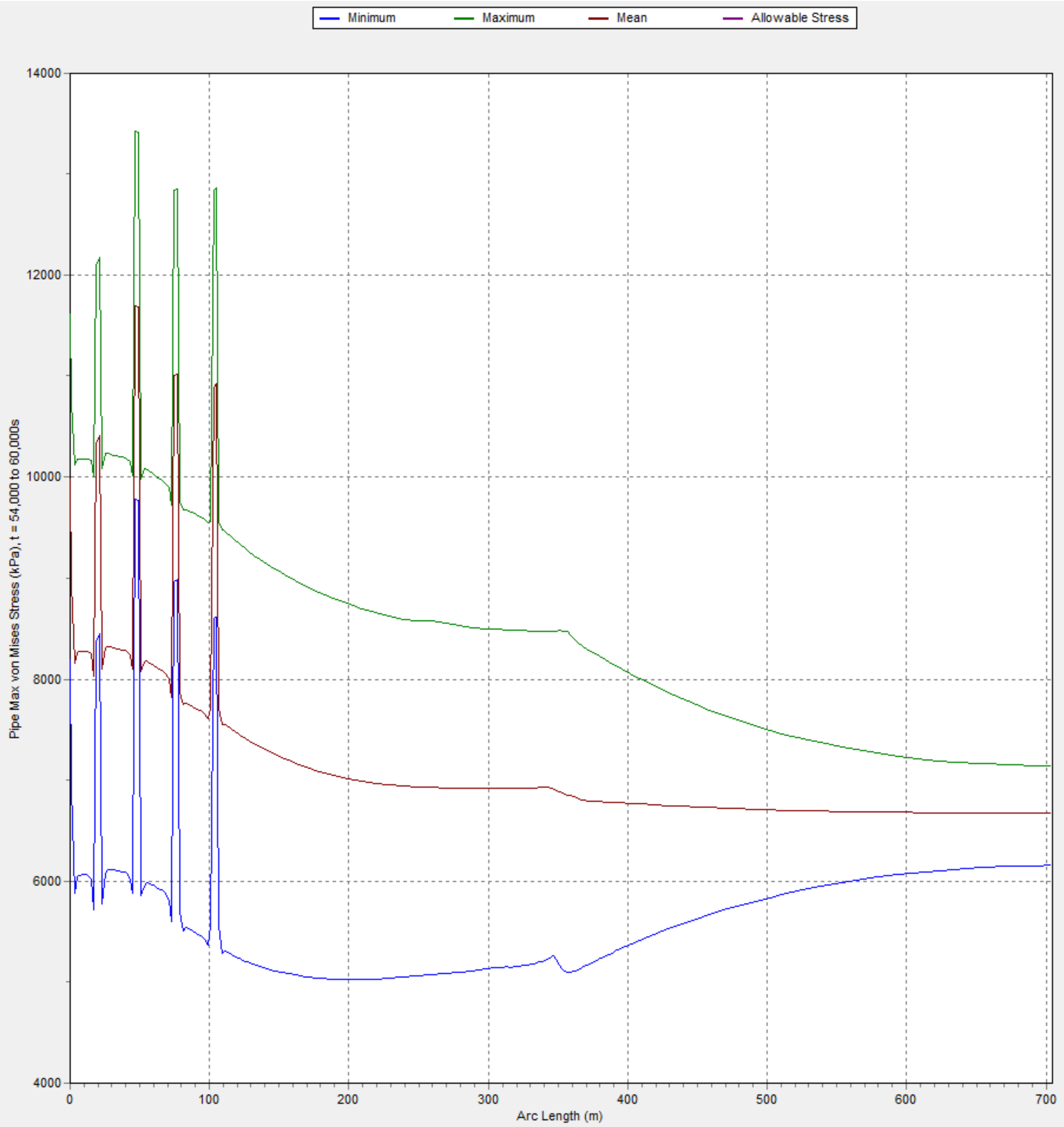

Diagram D.3 Max von Mises Stress vs Arc Length, Dynamic State (Case 0°)

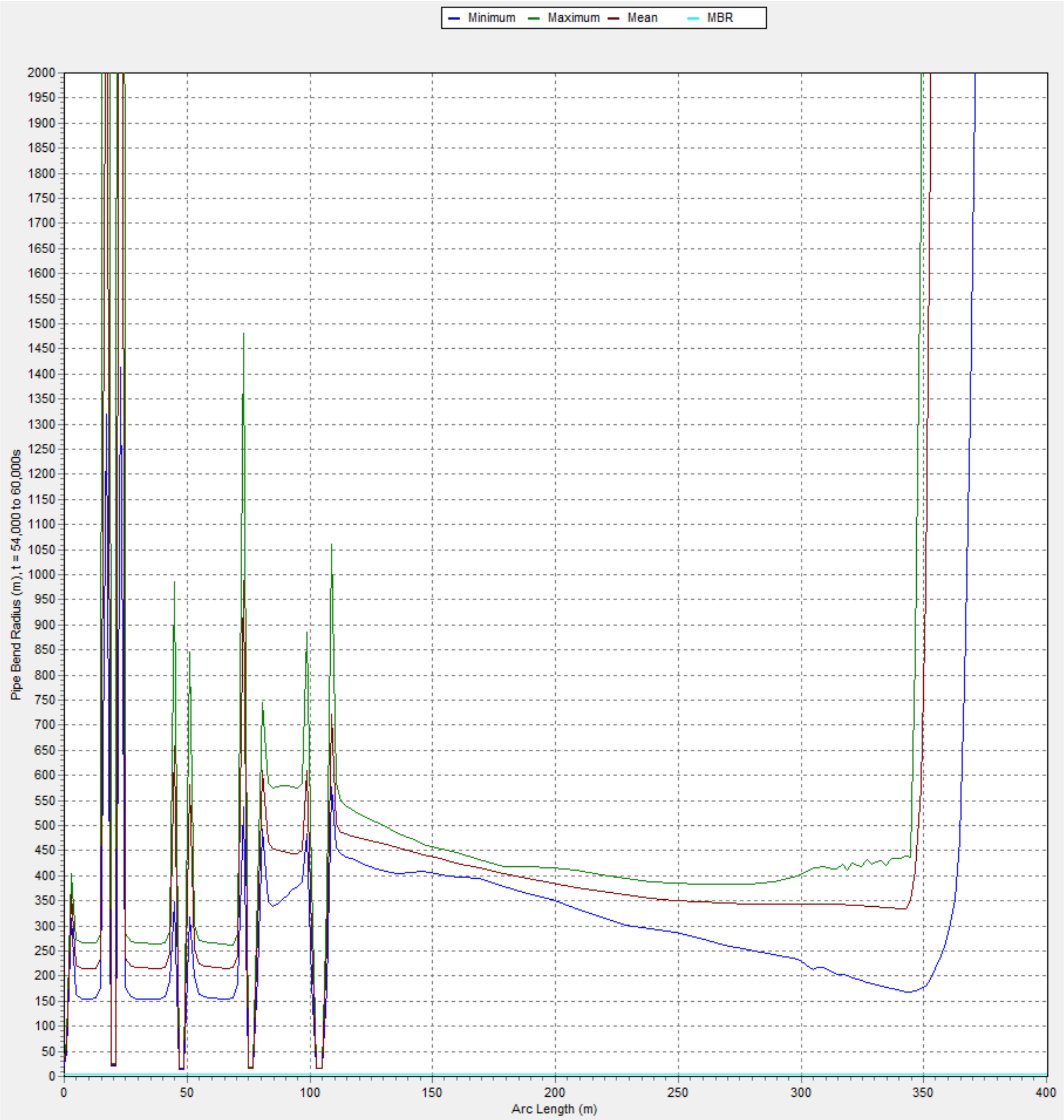

Diagram D.4 Pipe bending Radius vs Arc Length, Dynamic State (Case 30°)

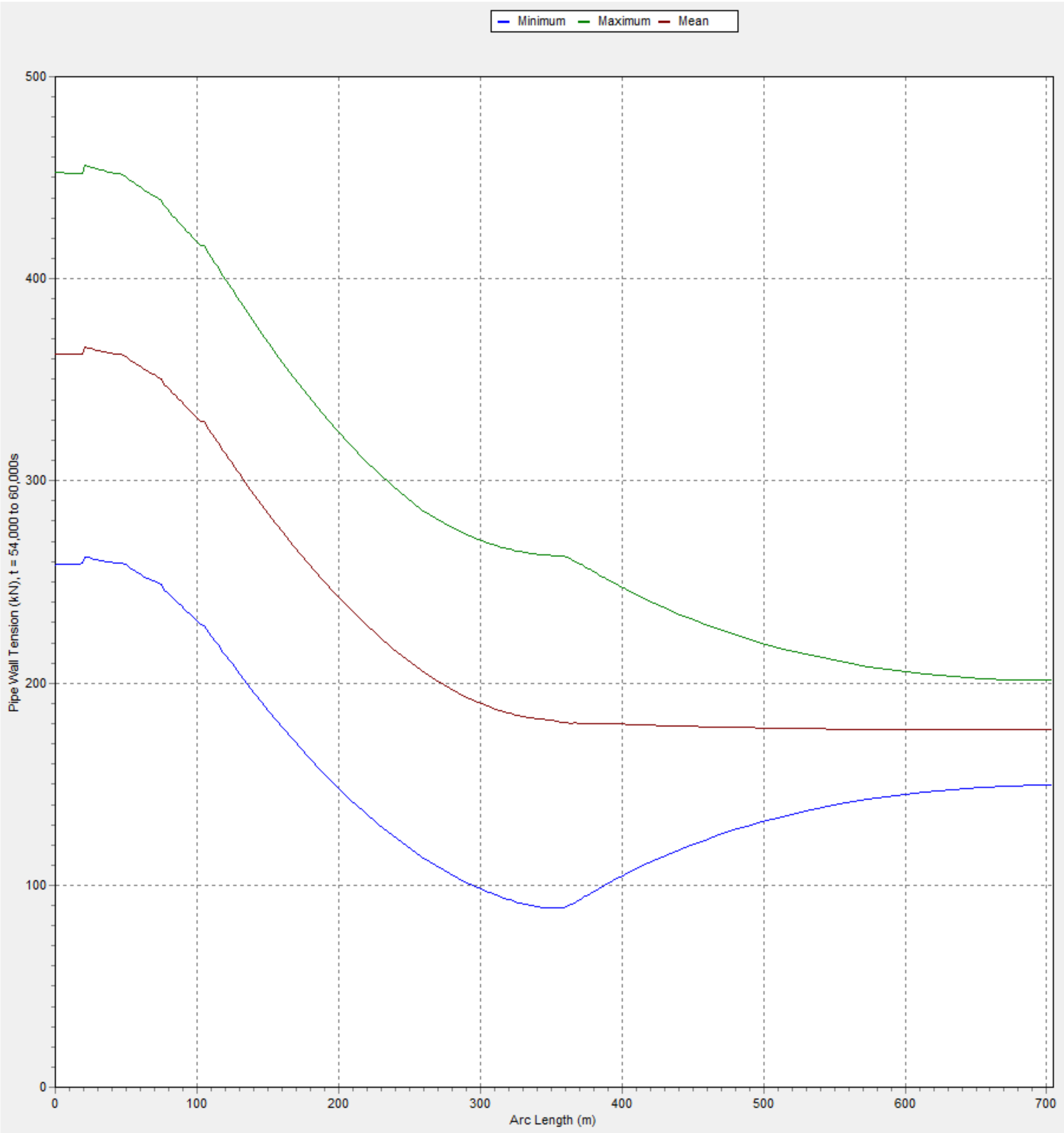

Diagram D.5 Wall Tension vs Arc Length, Static State (Case 30°)

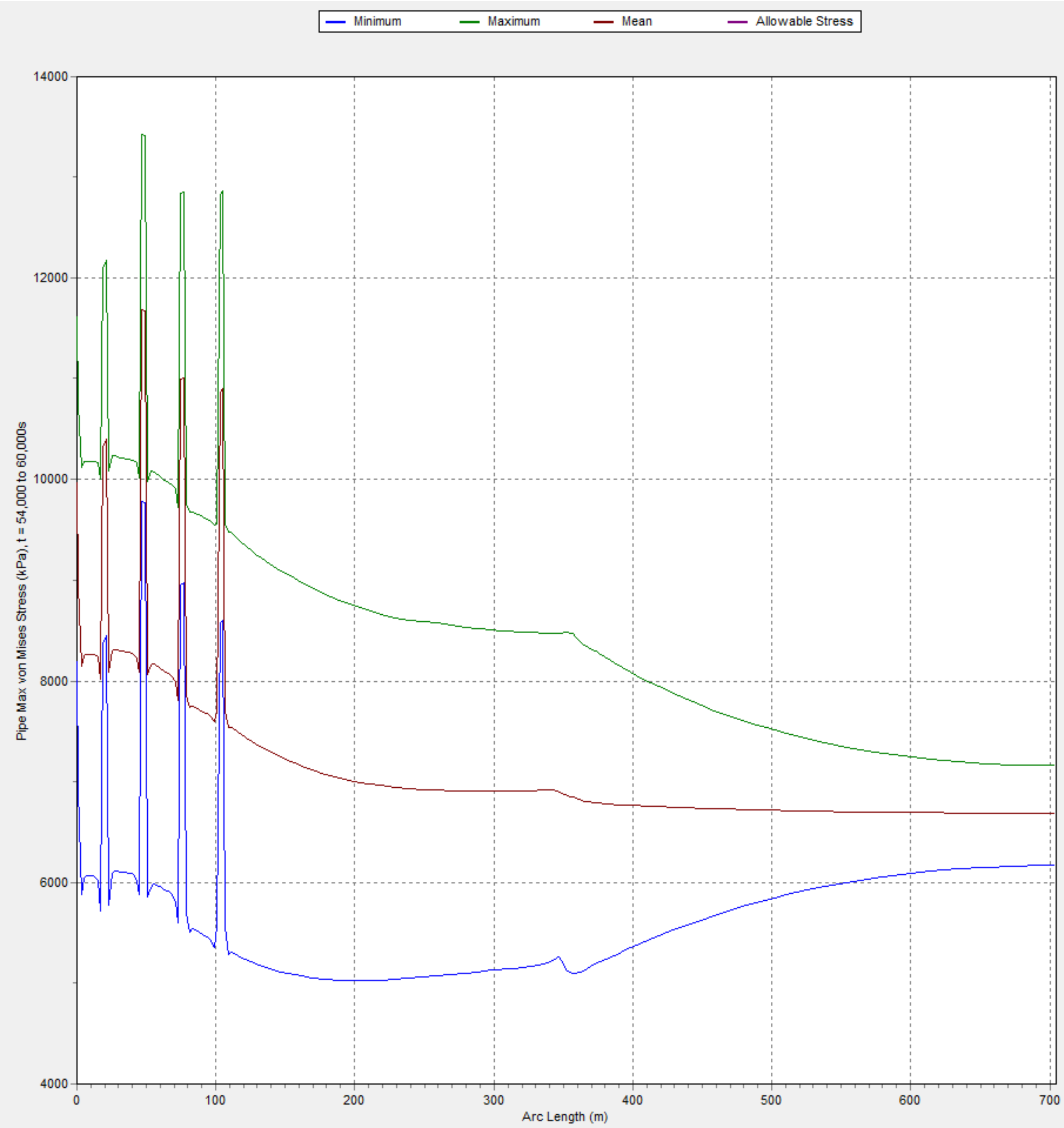

Diagram D.6 Max von Mises Stress vs Arc Length, Static State (Case 30°)

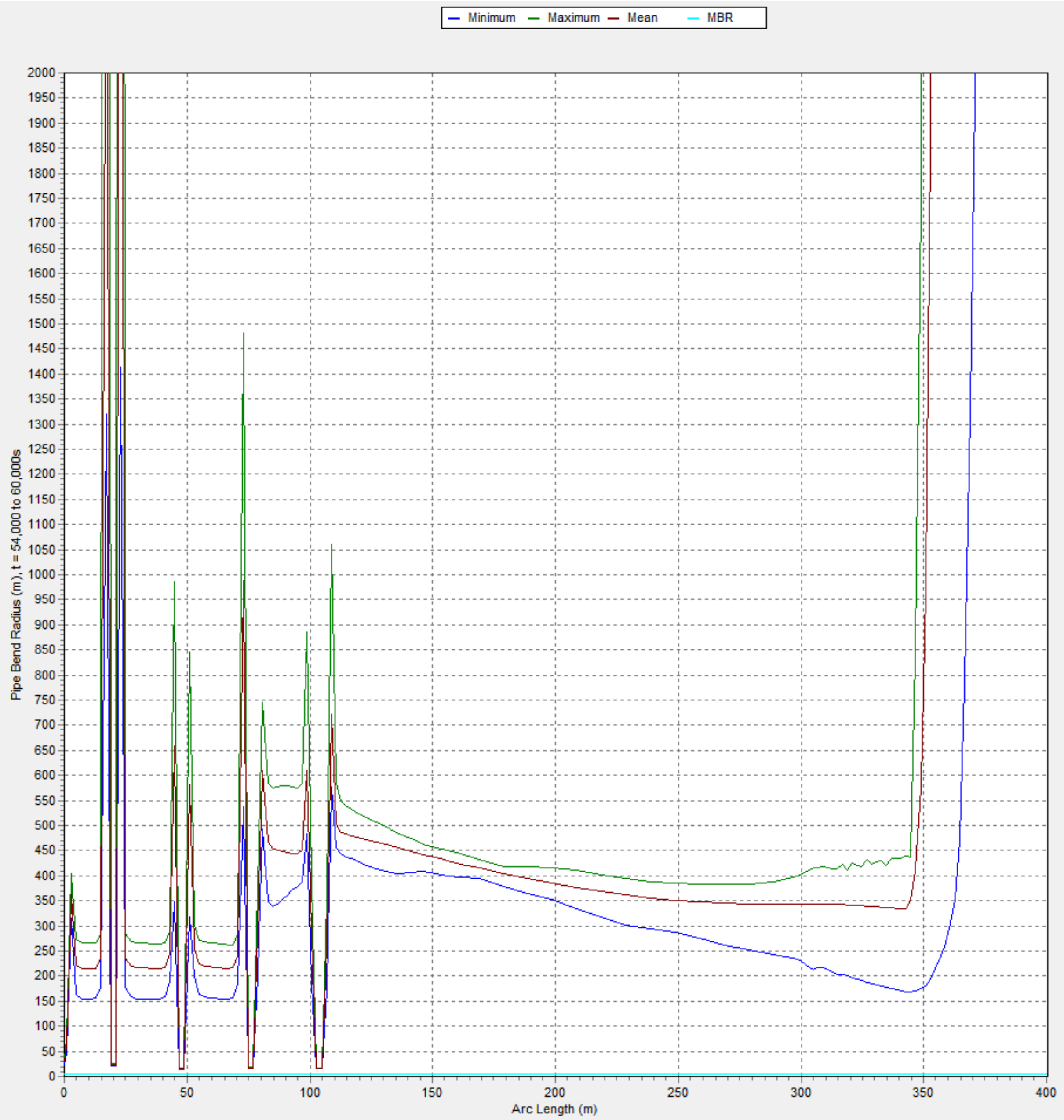

Diagram D.7 Pipe bending Radius vs Arc Length, Dynamic State (Case 60°)

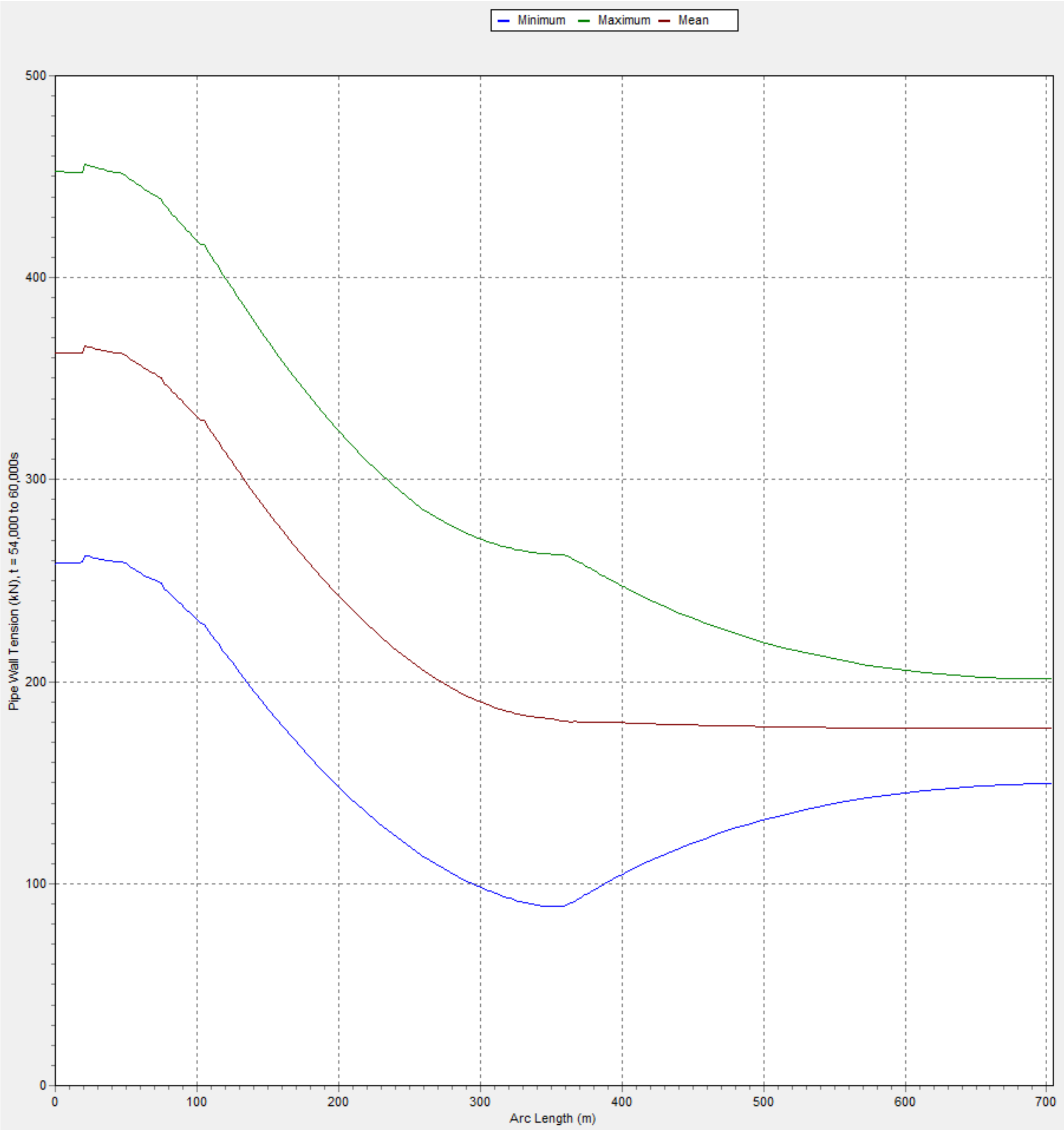

Diagram D.8 Wall Tension vs Arc Length, Static State (Case 60°)

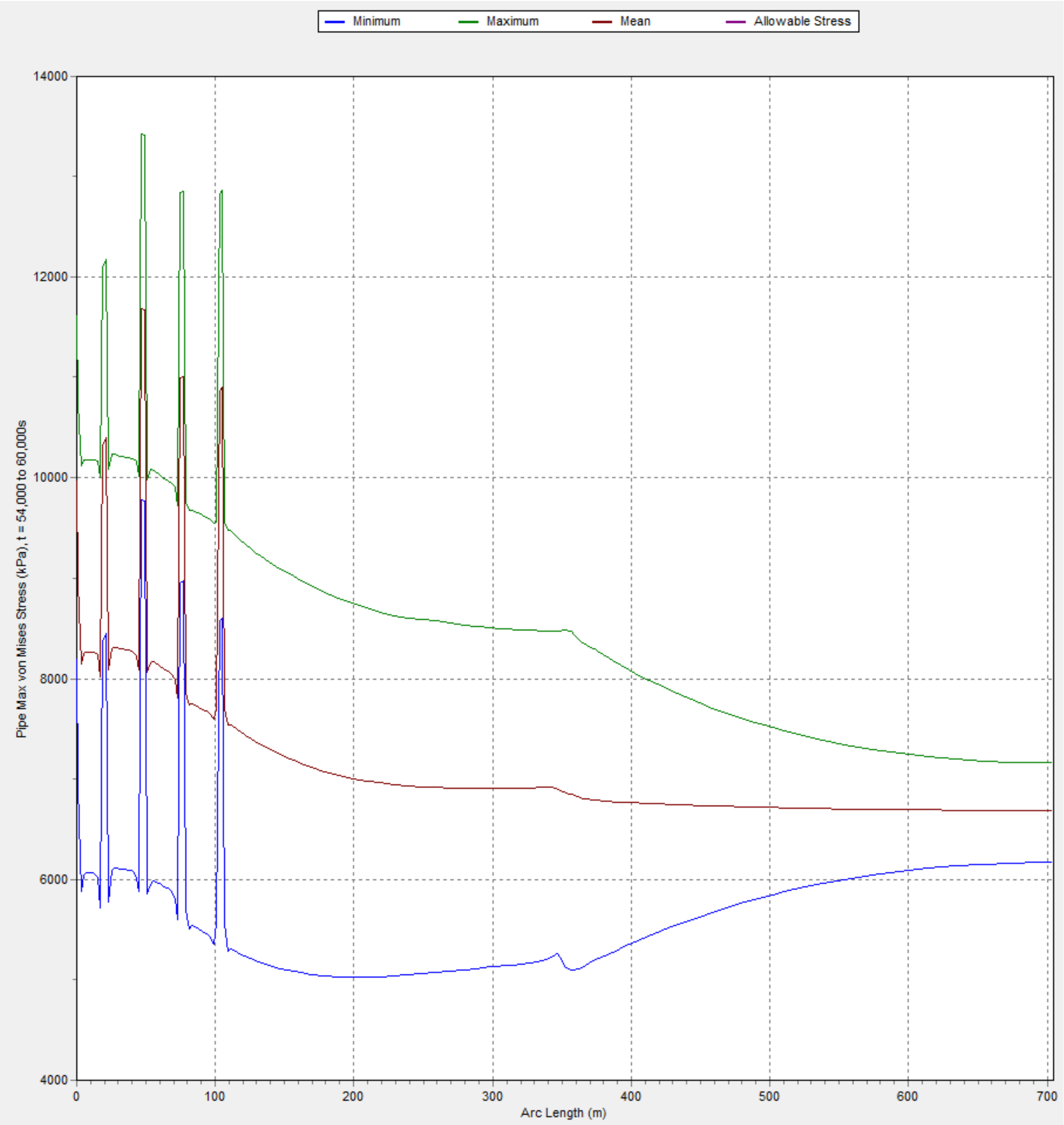

Diagram D.9 Max von Mises Stress vs Arc Length, Static State (Case 60°)

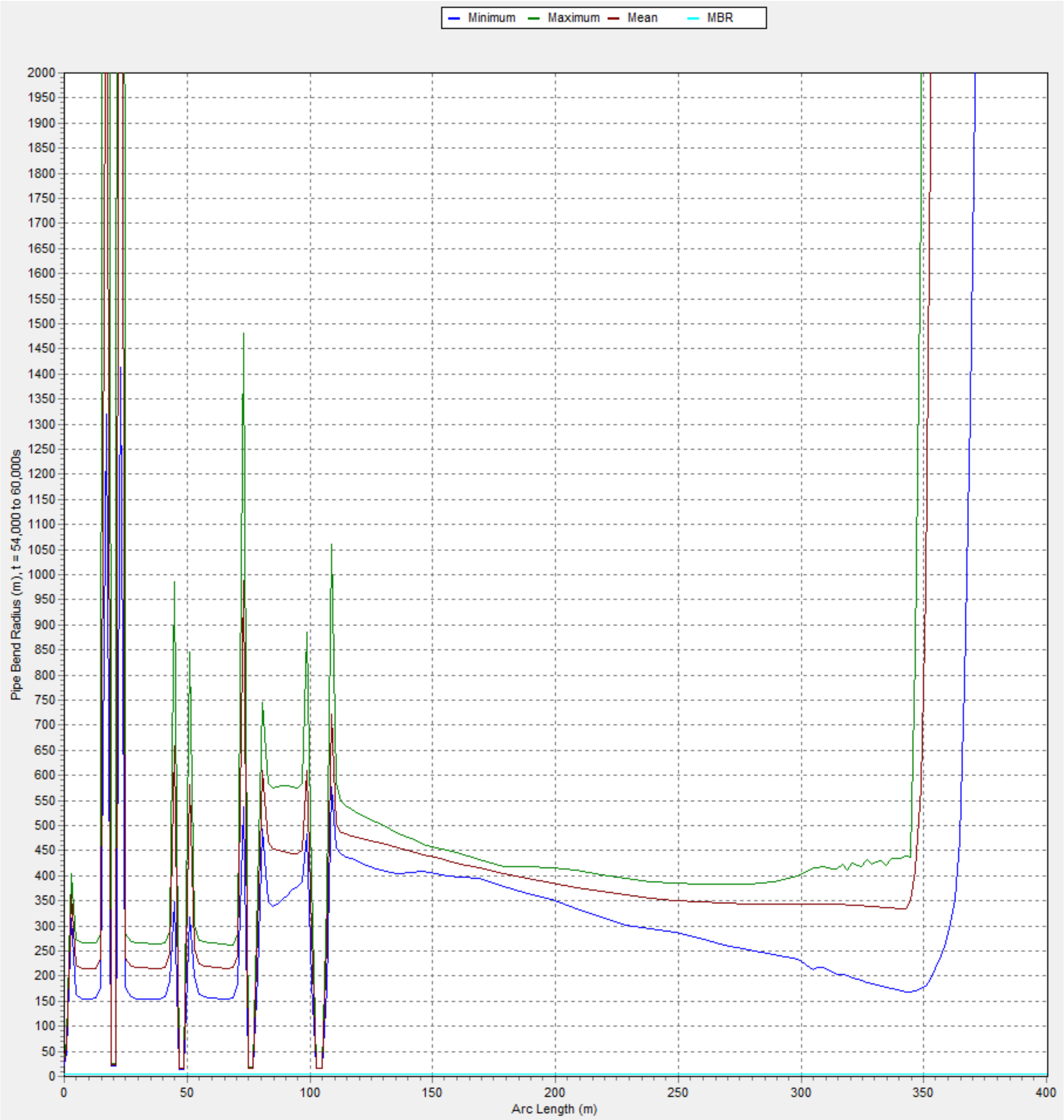

Diagram D.10 Pipe bending Radius vs Arc Length, Dynamic State (Case 120°)

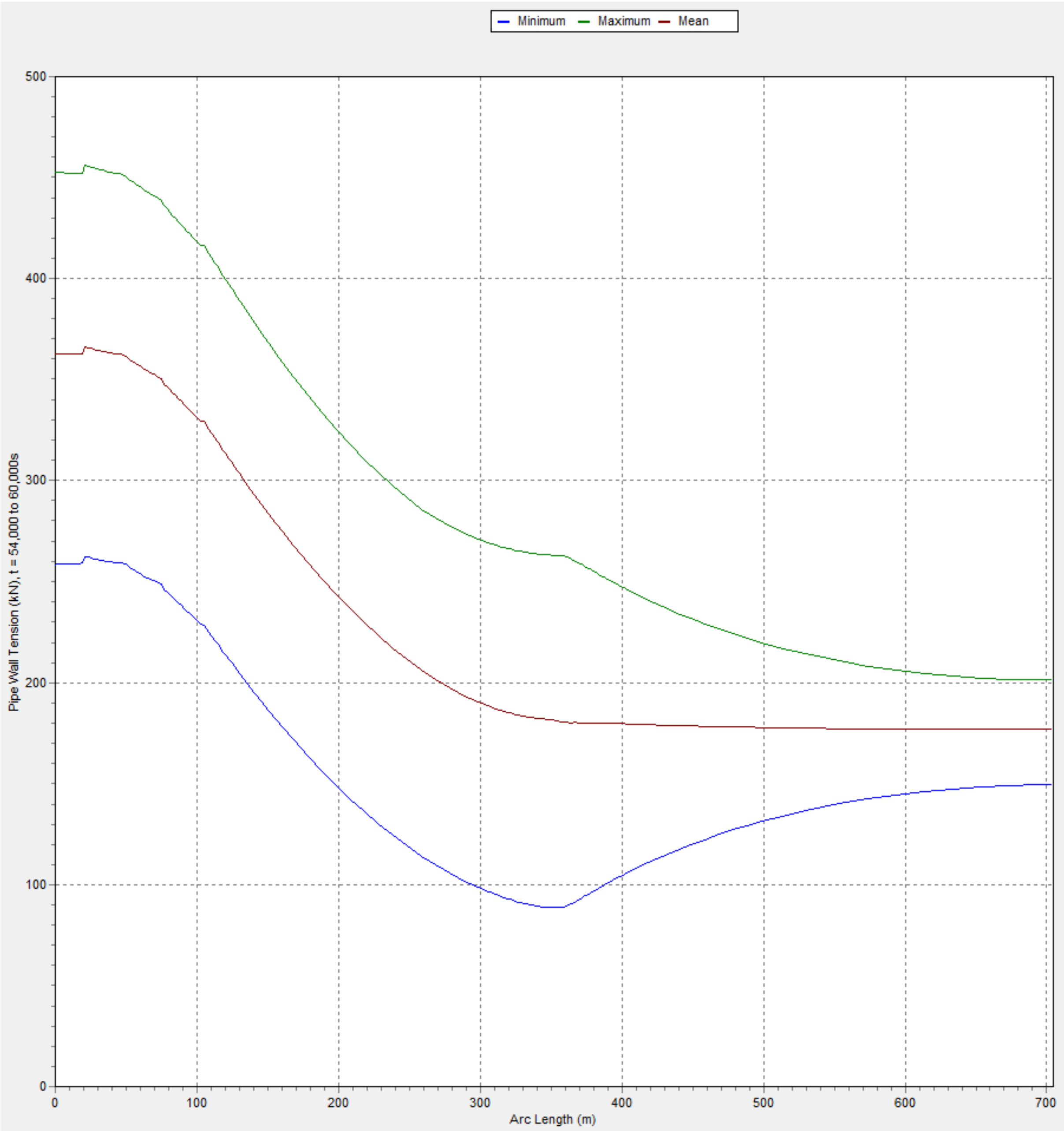

Diagram D.11 Wall Tension vs Arc Length, Dynamic State (Case 120°)

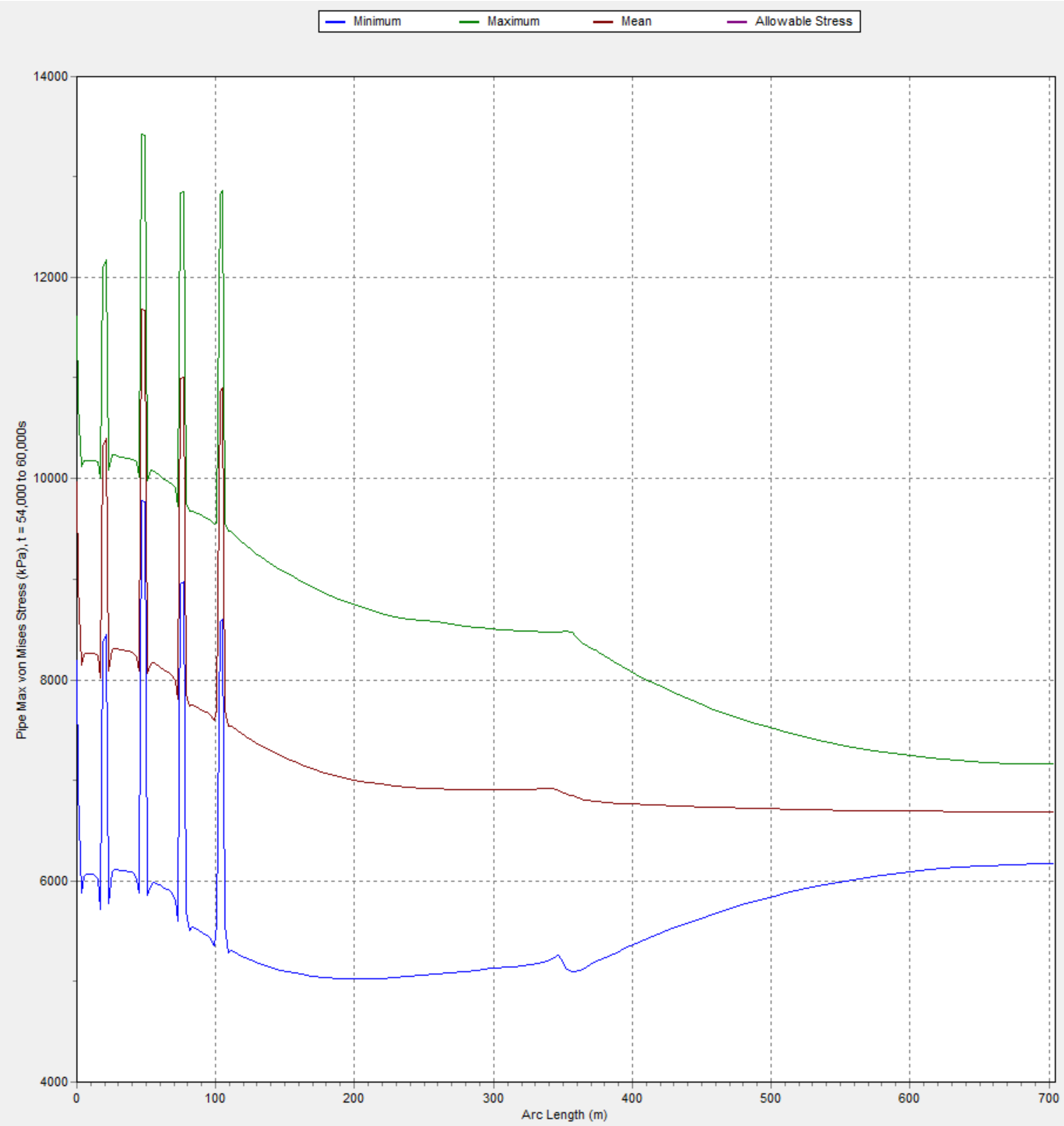

Diagram D.12 Max von Mises Stress vs Arc Length, Dynamic State (Case 120°)

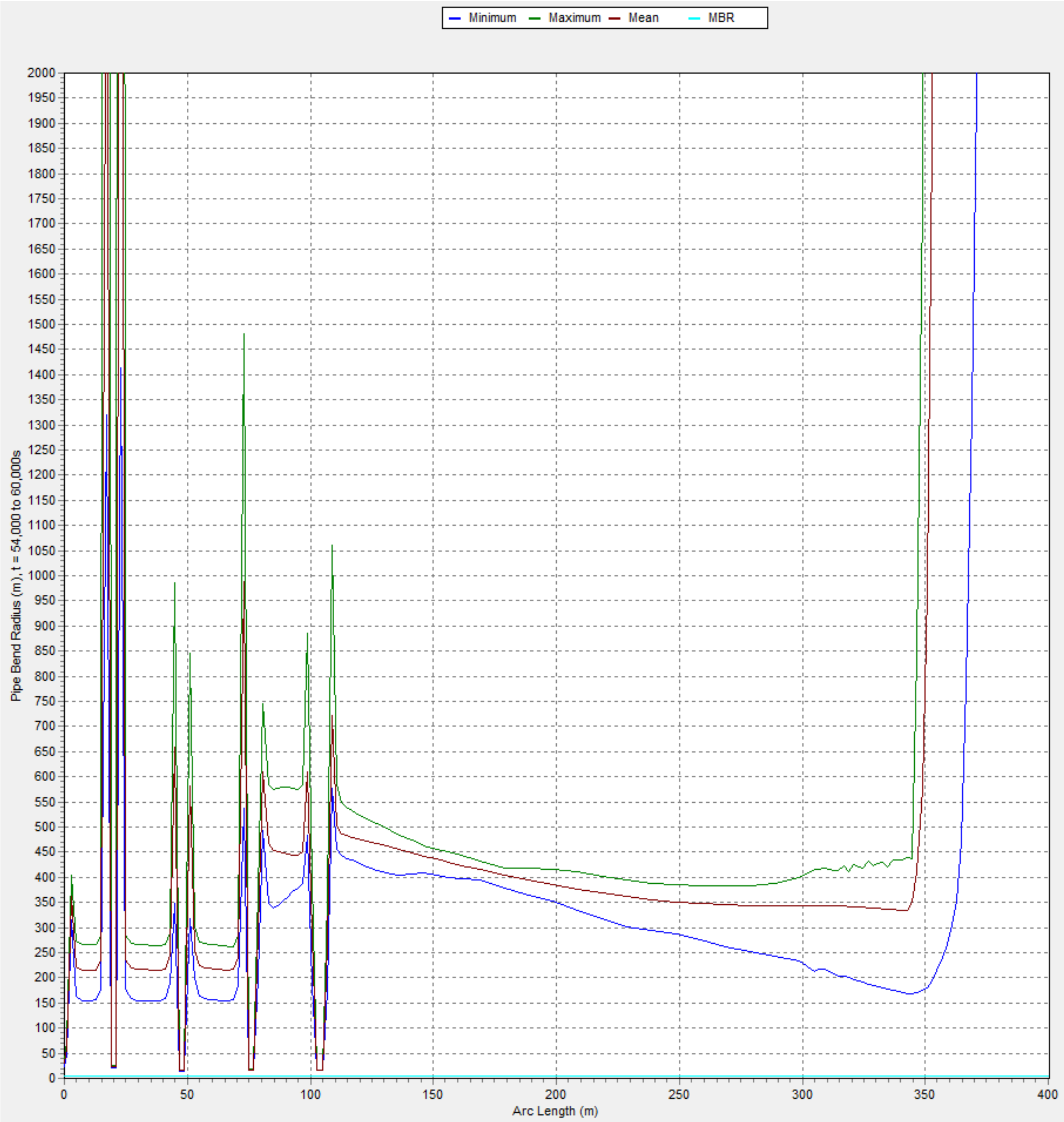

Diagram D.13 Pipe bending Radius vs Arc Length, Dynamic State (Case 150°)

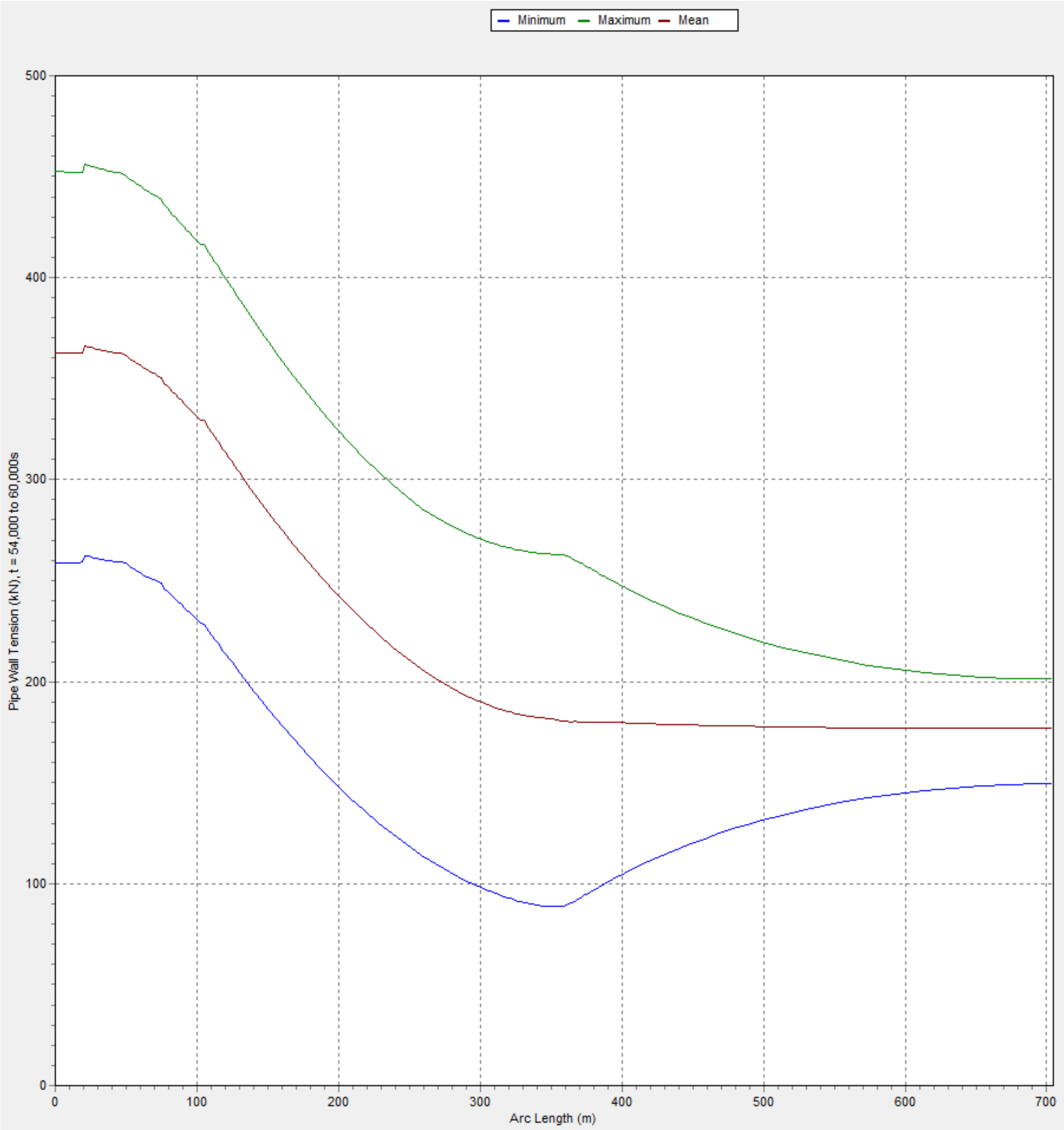

Diagram D.14 Wall Tension vs Arc Length, Dynamic State (Case 150°)

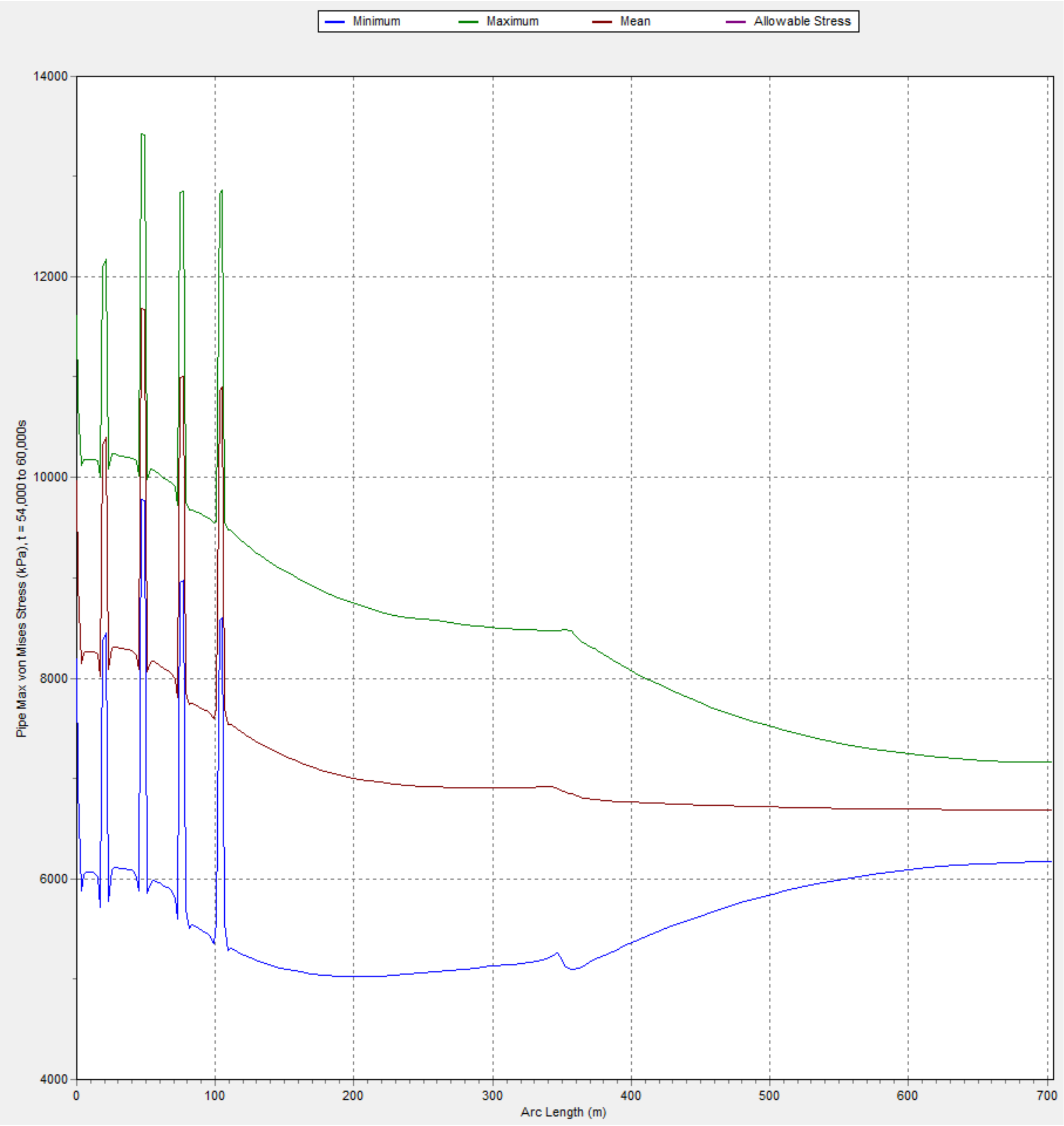

Diagram D.15 Max von Mises Stress vs Arc Length, Dynamic State (Case 150°)

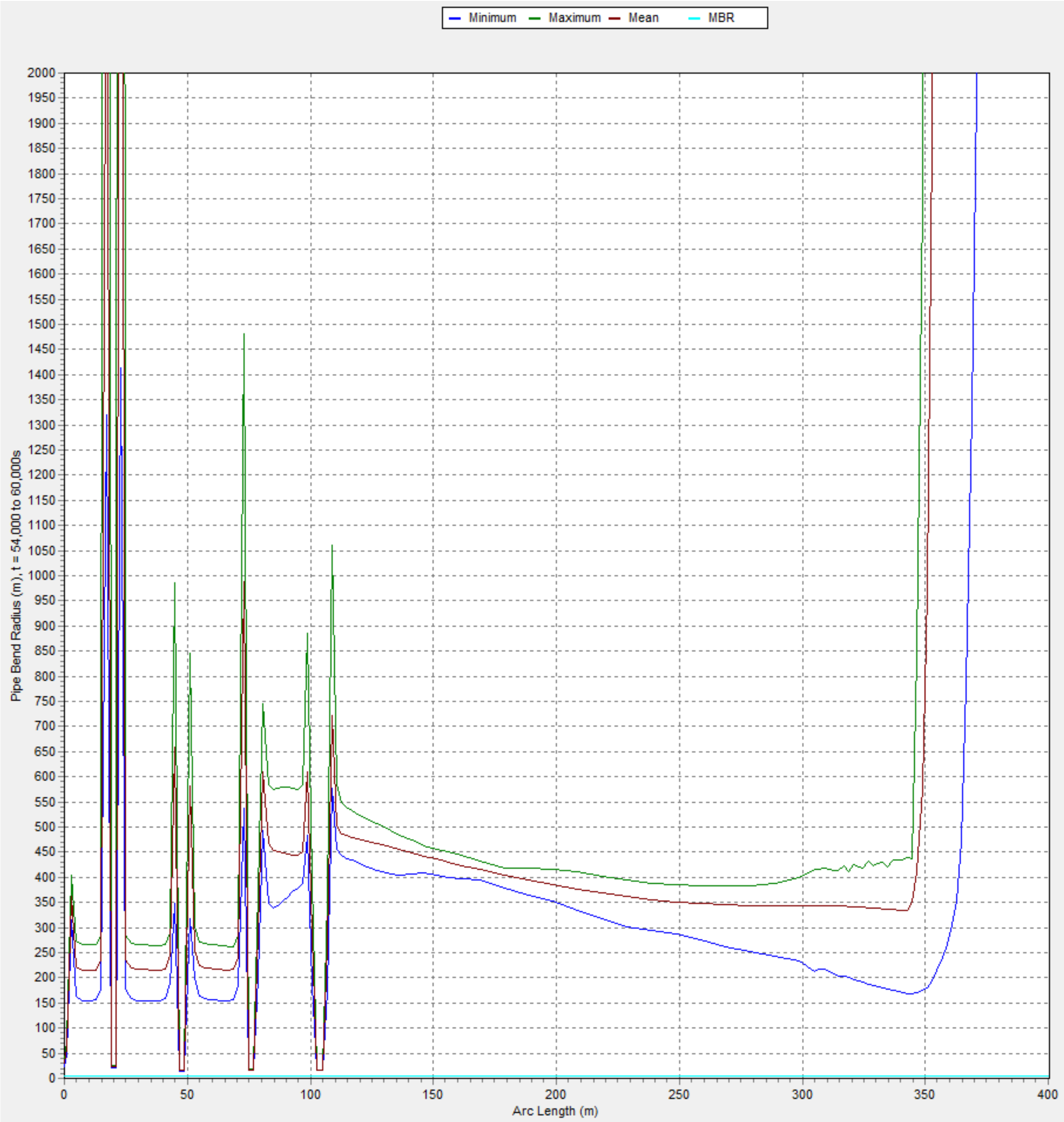

Diagram D.16 Pipe bending Radius vs Arc Length, Dynamic State (Case 180°)

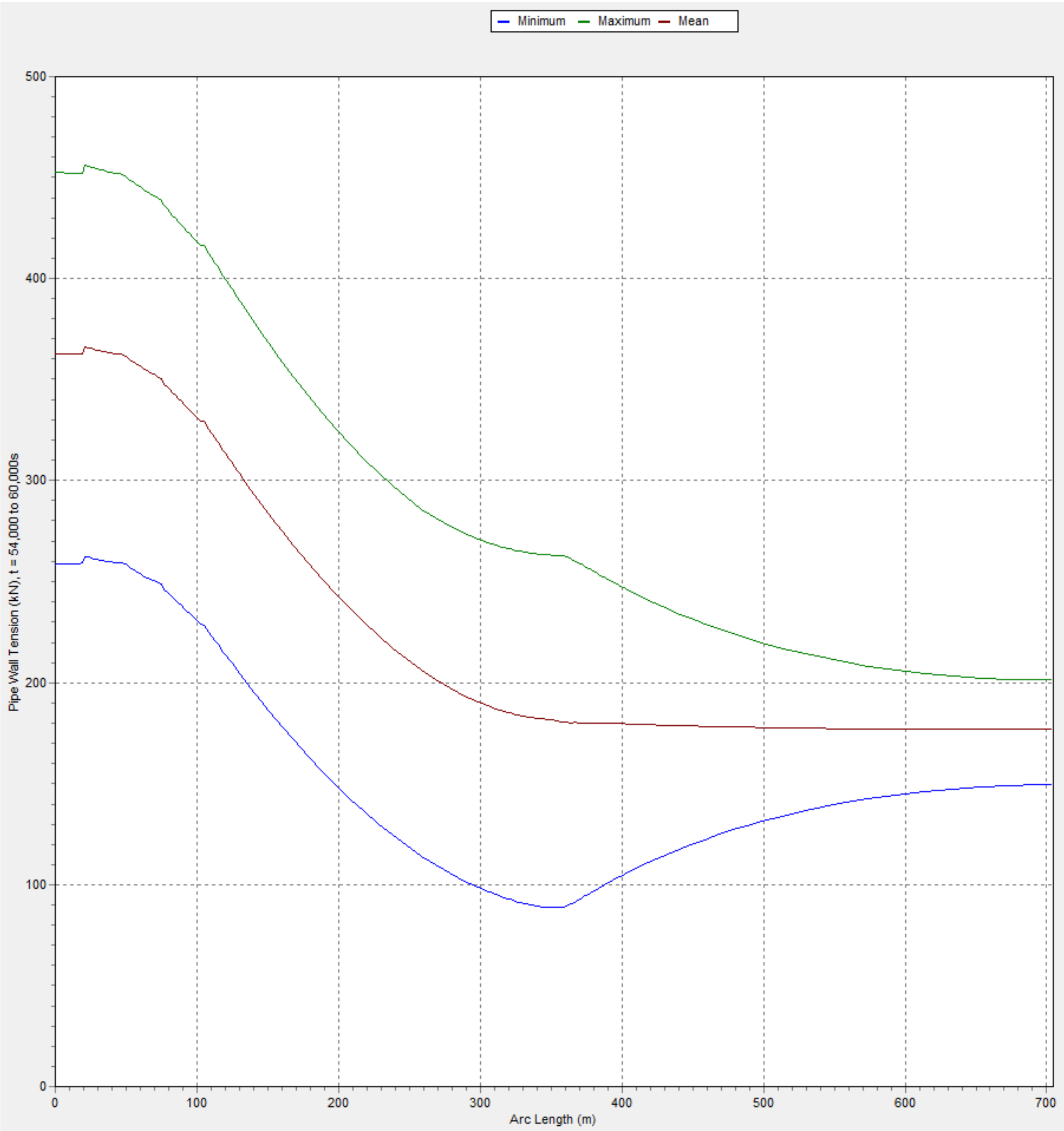

Diagram D.17 Wall Tension vs Arc Length, Dynamic State (Case 180°)

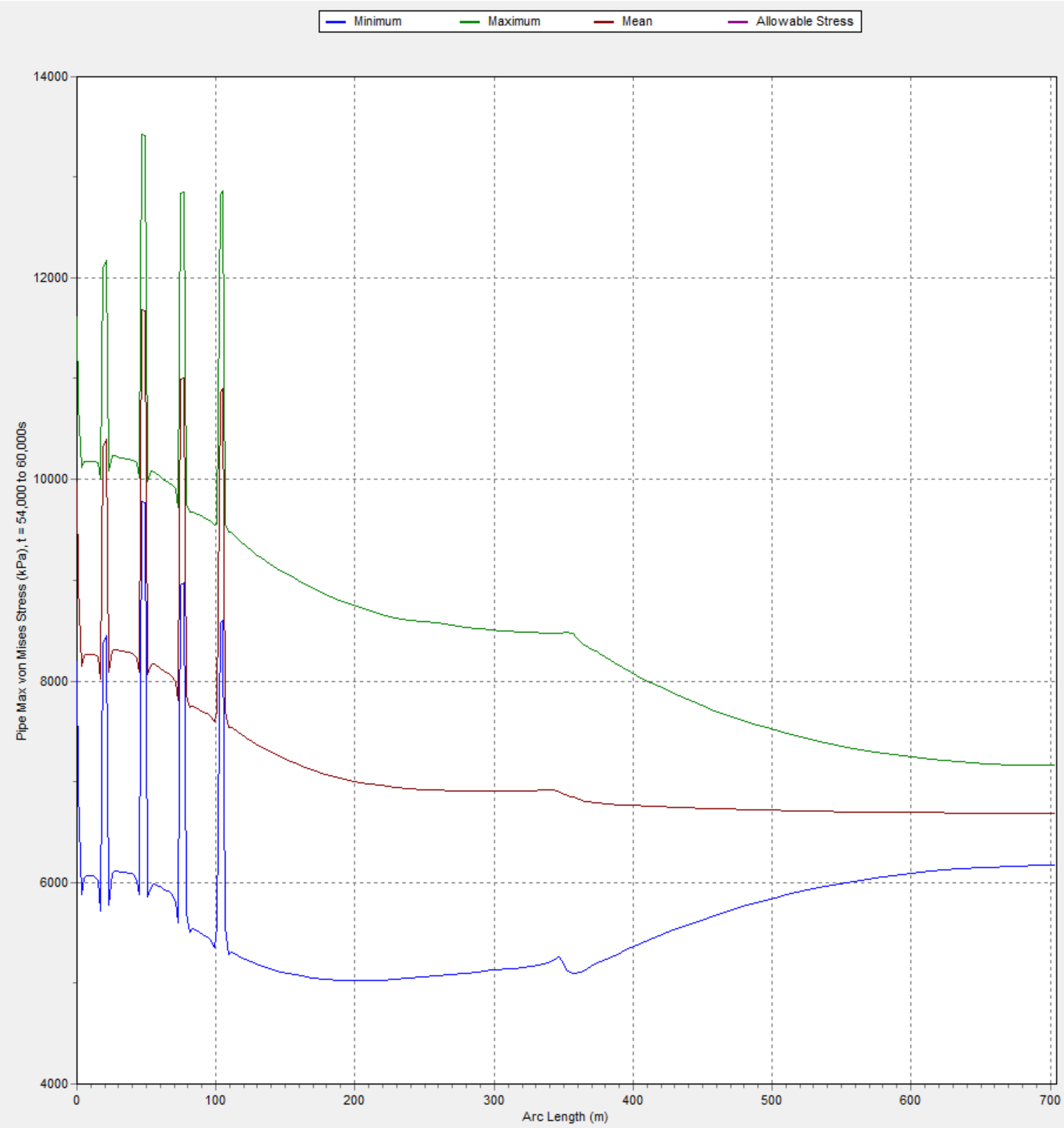

Diagram D.18 Max von Mises Stress vs Arc Length, Dynamic State (Case 180°)

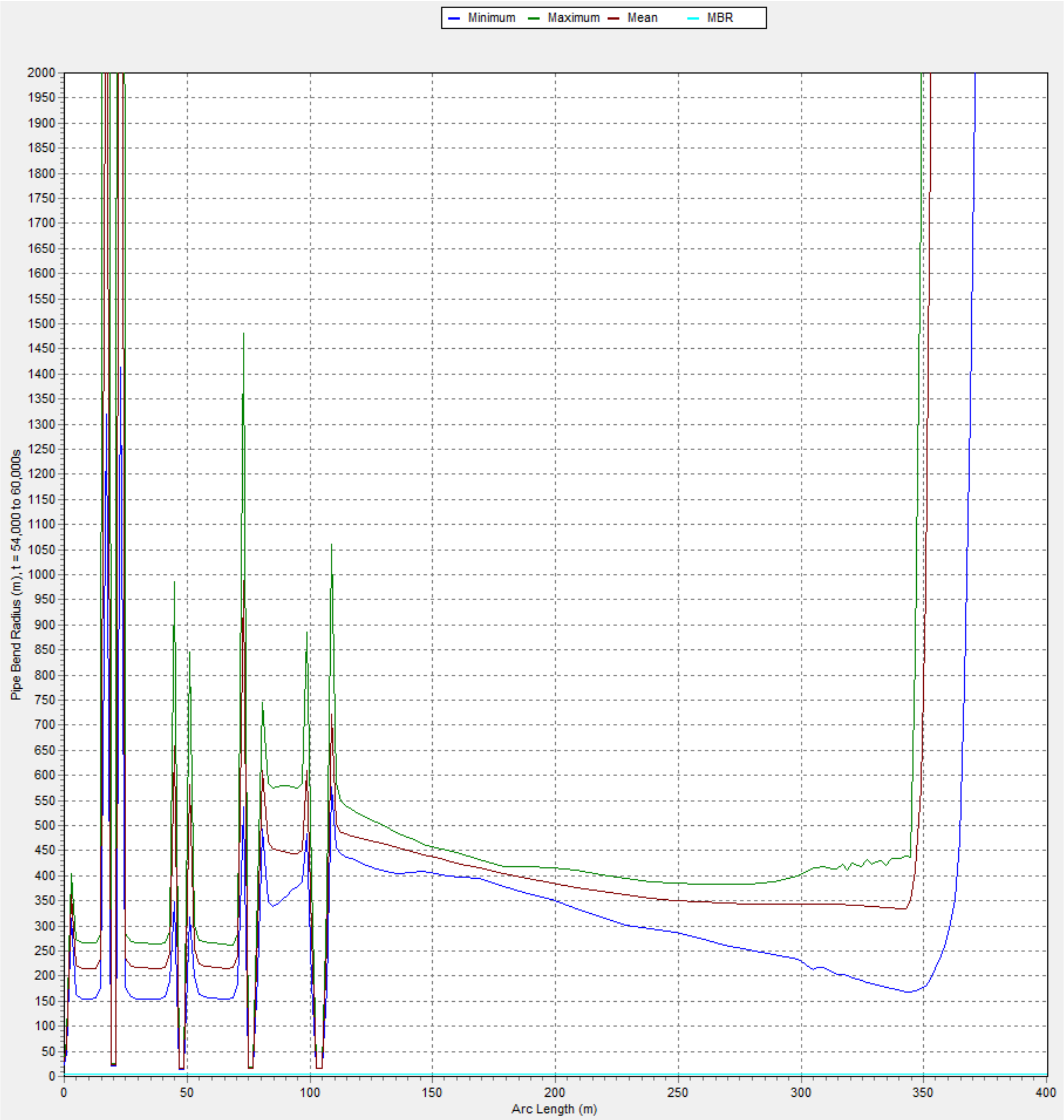

Diagram D.19 Pipe bending Radius vs Arc Length, Dynamic State (No Current)

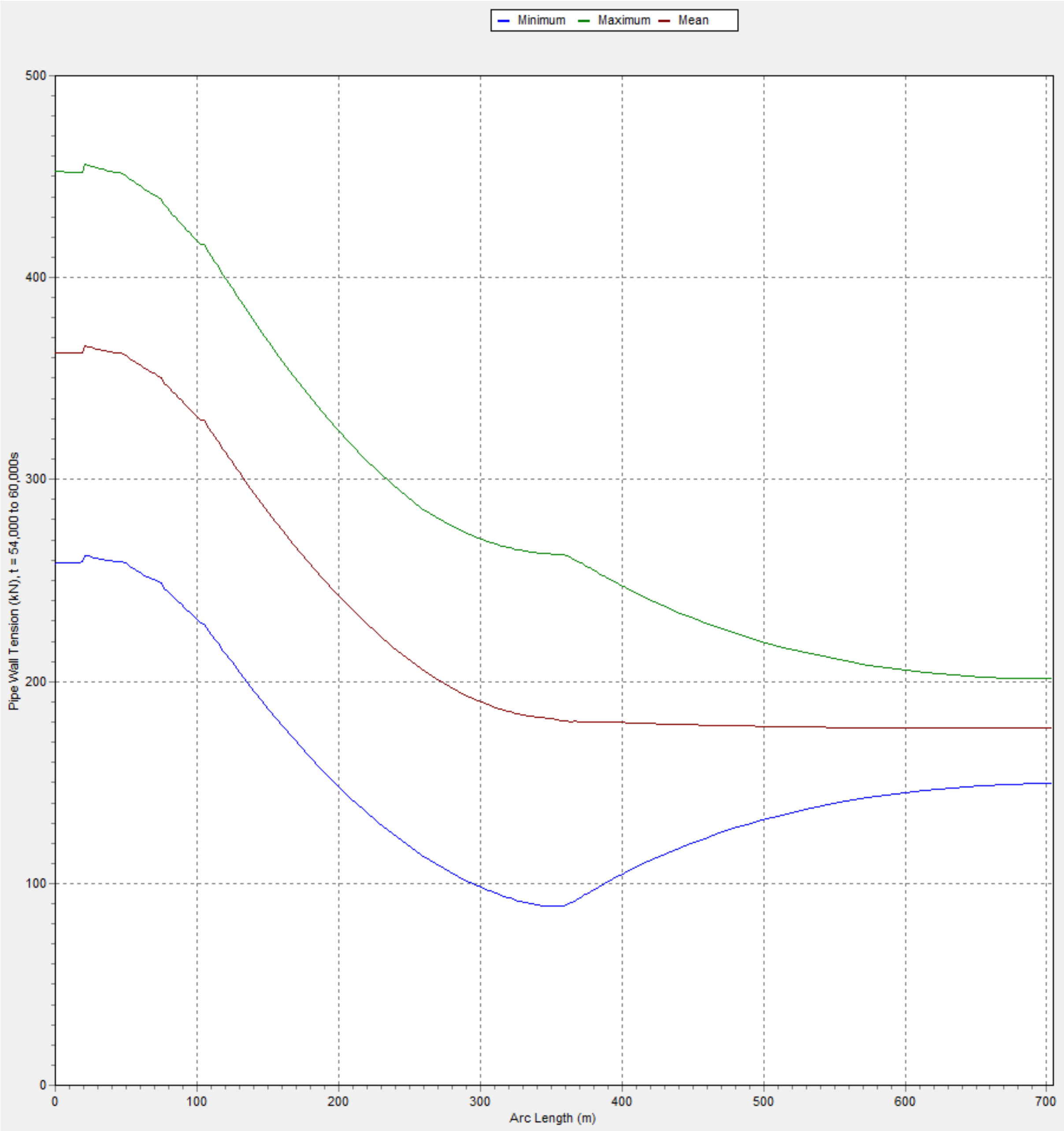

Diagram D.20 Wall Tension vs Arc Length, Dynamic State (No Current)

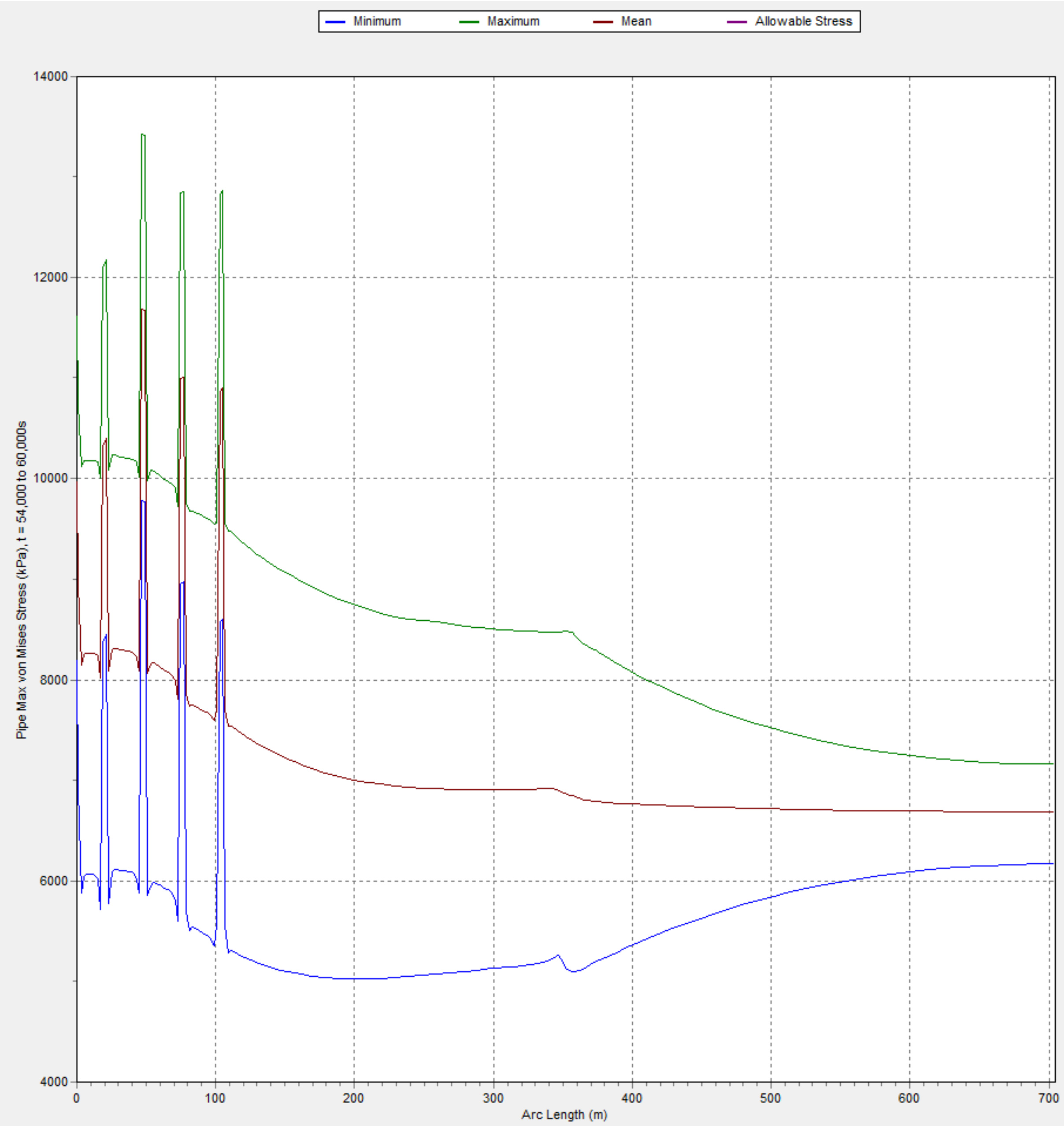

Diagram D.21 Max von Mises Stress vs Arc Length, Dynamic State (No Current)